EA-90-01

# ENVIRONMENTAL ASSESSMENT BOARD

Ontario

# ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARINGS

**VOLUME:** 108

**DATE:** Monday, February 17, 1992

**BEFORE:**

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| HON. MR. JUSTICE E. SAUNDERS | Chairman |
| DR. G. CONNELL | Member |
| MS. G. PATTERSON | Member |

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(416) 482-3277

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EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD
ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARING

IN THE MATTER OF the Environmental Assessment Act, R.S.O. 1980, c. 140, as amended, and Regulations thereunder;

AND IN THE MATTER OF an undertaking by Ontario Hydro consisting of a program in respect of activities associated with meeting future electricity requirements in Ontario.

Held on the 5th Floor, 2200 Yonge Street, Toronto, Ontario, on Monday, the 17th day of February, 1992, commencing at 10:00 a.m.

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VOLUME 108
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B E F O R E :

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| THE HON. MR. JUSTICE E. SAUNDERS | Chairman |
| DR. G. CONNELL | Member |
| MS. G. PATTERSON | Member |

S T A F F :

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|---|---|
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| MR. R. NUNN | Counsel/Manager, Information Systems |
| MS. C. MARTIN | Administrative Coordinator |
| MS. G. MORRISON | Executive Coordinator |

# A P P E A R A N C E S

| | | |
|---|---|---|
| B. CAMPBELL | ) | ONTARIO HYDRO |
| L. FORMUSA | ) | |
| B. HARVIE | ) | |
| J.F. HOWARD, Q.C. | ) | |
| J. LANE | ) | |
| G. A. KARISH | ) | |
| J.C. SHEPHERD | ) | IPPSO |
| I. MONDROW | ) | |
| J. PASSMORE | ) | |
| R. WATSON | ) | MUNICIPAL ELECTRIC ASSOCIATION |
| A. MARK | ) | |
| S. COUBAN | ) | PROVINCIAL GOVERNMENT AGENCIES |
| P. MORAN | ) | |
| J. MacDONALD | ) | |
| C. MARLATT | ) | NORTH SHORE TRIBAL COUNCIL, UNITED CHIEFS AND COUNCILS OF MANITOULIN, UNION OF ONTARIO INDIANS |
| D. ESTRIN | ) | |
| D. POCH | ) | COALITION OF ENVIRONMENTAL GROUPS |
| D. STARKMAN | ) | |
| D. ARGUE | ) | |
| T. ROCKINGHAM | | MINISTRY OF ENERGY |
| B. KELSEY | ) | NORTHWATCH |
| L. GREENSPOON | ) | |
| P. McKAY | ) | |
| J.M. RODGER | | AMPCO |
| M. MATTSON | ) | ENERGY PROBE |
| D. CHAPMAN | ) | |
| A. WAFFLE | | ENVIRONMENT CANADA |
| M. CAMPBELL | ) | ONTARIO PUBLIC HEALTH ASSOCIATION, INTERNATIONAL INSTITUTE OF CONCERN FOR PUBLIC HEALTH |
| M. IZZARD | ) | |
| G. GRENVILLE-WOOD | | SESCI |

# A P P E A R A N C E S
(Cont'd)

| | |
|---|---|
| D. ROGERS | ONGA |
| H. POCH )<br>J. PARKINSON ) | CITY OF TORONTO |
| R. POWER | CITY OF TORONTO,<br>SOUTH BRUCE ECONOMIC CORP. |
| S. THOMPSON | ONTARIO FEDERATION OF AGRICULTURE |
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| J. MONGER )<br>K. ROSENBERG )<br>C. GATES ) | CAC (ONTARIO) |
| W. TRIVETT | RON HUNTER |
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| T. HILL | TOWN OF NEWCASTLE |
| M. OMATSU )<br>B. ALLISON )<br>C. REID ) | OMAA |
| E. LOCKERBY | AECL |
| C. SPOEL )<br>U. FRANKLIN )<br>B. CARR ) | CANADIAN VOICE OF WOMEN FOR PEACE |
| F. MACKESY | ON HER OWN BEHALF |
| D. HUNTER )<br>M. BADER ) | DOFASCO |
| B. TAYLOR )<br>D. HORNER )<br>H. WATSON ) | MOOSONEE DEVELOPMENT AREA BOARD AND CHAMBER OF COMMERCE |

APPEARANCES
(Cont'd)

| | | |
|---|---|---|
| T. HEINTZMAN | ) | ATOMIC ENERGY OF CANADA |
| D. HAMER | ) | |
| C. FINDLAY | ) | |
| P.A. NYKANEN | ) | CANADIAN MANUFACTURERS ASSOCIATION - ONTARIO |
| G. MITCHELL | | SOCIETY OF AECL PROFESSIONAL EMPLOYEES |
| S. GOUDGE | | CUPE |
| D. COLBORNE | | NIPIGON ABORIGINAL PEOPLES' ALLIANCE |

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## L I S T of E X H I B I T S

## TIME NOTATIONS

---Upon commencing at 10:00 a.m.

THE REGISTRAR: Please come to order. This hearing is now in session. Please be seated.

THE CHAIRMAN: Mr. Howard? Perhaps, first of all, I have been asked to put it into the record so it is on the transcript some exhibits that have come in since we last met.

Number 467, filed by Ontario Hydro, the update to the 1990 long-term load forecast; 468, filed by Ontario Hydro, "Materials Relating to Environmental and Health Effects of Fossil Generation"; and 469, filed by Northwatch, "Northwatch Intervention Coalition Document Precis".

---EXHIBIT NO. 467: Update to the 1990 long-term load forecast, filed by Ontario Hydro.

---EXHIBIT NO. 468: "Materials Relating to Environmental and Health Effects of Fossil Generation," filed by Ontario Hydro.

---EXHIBIT NO. 469: "Northwatch Intervention Coalition Document Precis."

THE CHAIRMAN: I understand, Mr. Howard, that there are no problems arising out of the scoping session; is that correct?

MR. HOWARD: That's correct, sir. Yes.

THE CHAIRMAN: I just would like to mention that I understand also that the order of

cross-examination has been settled, subject to some timing problems that some parties may have.

I know you have done this before and you will do it again, that you keep in touch with Ms. Morrison who will do the best she can to arrange it as expeditiously as possible. But let me say that the responsibility is on the party, not on Ms. Morrison, to be ready when the time comes for them to participate in the cross-examination.

Mr. Howard?

MR. HOWARD: Thank you, Mr. Chairman.

Mr. Chairman, the summary curriculum vitae of all of the witnesses on this panel, except for Mr. Burpee, were filed as part of Exhibit 98, which was filed August, 1990. Mr. Burpee's curriculum vitae is annexed to Exhibit 464, which was filed January the 27th, but if I may just spend a moment with each of the witnesses, except Mr. Shalaby whom you have seen before, to flesh out the CVs a little bit.

First, Dr. Effer, I understand that yours needs correction because at the moment it shows that you are the Manager, Environmental Studies and Assessment Department, Design and Development Division, Generation, 1979...blank. But I understand you have had the shortest retirement on record because you

retired officially December 31st.

Is that correct, sir?

DR. EFFER: That's correct.

MR. HOWARD: In looking at your CV, you were trained in chemistry and botany and obtained your Ph.D. in plant biochemistry and joined Hydro ultimately in 1967--

DR. EFFER: That's correct.

MR. HOWARD: --as a biologist in the Research Division, and in 1970 you joined the Environmental Studies Group and have been with that group ever since?

DR. EFFER: That's correct, yes.

MR. HOWARD: Would you just describe briefly for the Board your functions and your responsibilities as Manager, Environmental Studies and Assessment Department, please?

DR. EFFER: As manager of the department, the department is directly responsible to the Design and Construction Branch for all environmental services.

THE CHAIRMAN: I hesitate to interrupt, but perhaps these witnesses ought to be sworn in first? We have been swearing witnesses in, and perhaps that should be done first.

MR. HOWARD: I've done it again. I did

that last June.

THE CHAIRMAN: Yes, you did.

MR. HOWARD: And you caught me then, too, sir. [Laughter]

THE CHAIRMAN: It's been our practice, so we should continue to do it.

Mr. Registrar?

DR. ARTHUR RAYMOND EFFER,
CHARLES WILLIAM DAWSON,
JAMES RICHARD BURPEE,
GARY NEIL MEEHAN,
JOHN DOUGLAS SMITH; Sworn.
AMIR SHALABY; Recalled.

DIRECT EXAMINATION BY MR. HOWARD:

Q. Dr. Effer, I guess I should ask you to adopt the answers that you have given me so far. But now under oath would you do that, please?

DR. EFFER: A. You want me to proceed from the first sentence?

Q. No, just say "yes". [Laughter] That's a leading question.

A. Yes.

Q. Thank you. Now, would you tell us briefly what is involved in your job as Manager, Environmental Studies Group?

A. The department provides environmental services to the Design and Construction Branch of

Ontario Hydro, and we also provide environmental services on request to other divisions and branches of the Corporation.

Within the D&C Branch we provide the environmental services right from the very initial conceptual stage of generation. I should say that the department is involved in generation-related and not transmission-related matters.

We provide services through each of the phases of the lifecycle of a generator station from the conceptual phase through design and construction, and on commissioning we hand over our duties and responsibilities to operating groups in the operating divisions.

The primary role in the department over the last several years has been the preparation of environmental assessments, and we have prepared those for new generating stations and also for the facilities associated with those generating stations, such as flue gas desulphurization and more recently the conceptual environmental assessment for the Nuclear Fuel Waste Management Program.

Another part of our responsibilities later on in the lifecycle, once approval has been reached of the environmental assessment, we work

closely with the Design and Construction engineering staff to ensure that all the commitments made during the environmental assessment approval phase are recorded and put into effect during actual construction of the station. In other words, we carry out permitting and approvals for various major equipment that is to be installed, apart from the station itself.

Another main function is to carry out the environmental studies, the field studies, and much of the associated field work associated with getting approval under the Environmental Assessment Act and also carrying out field studies during what we call the pre-operational phase; that is, prior to the station coming on stream.

Further, we also conduct studies for several years after the station has been operating. My department's responsibility finishes on the preparation of what we call an Effects Report, which we report to the Ministry, which essentially tries to determine what effect a facility or a generating station has had on the environment.

I think that in brief covers most of it.

Q. Thank you, Dr. Effer.

Mr. Dawson, you were trained in mechanical engineering originally and joined Hydro in

1972 as an equipment studies engineer, and you are now a fossil projects planning engineer, Generation Planning and Approvals Department. Do I have that correctly?

MR. DAWSON: A. That's correct.

Q. Would you just describe for the Board, please, briefly what is involved in your work as a fossil projects planning engineer?

A. Yes. I am responsible for the design and construction activities associated with the early phases of the design of fossil fuel generation and the associated environmental control equipment.

These activities typically would include scheduling, estimating, conceptual and definition phases of the design leading to the approval by and the release by the Ontario Hydro board of directors.

At that point my responsibilities stop.

Q. Thank you. Mr. Shalaby, has your job changed since you were here last?

MR. SHALABY: A. Not significantly, no.

Q. Mr. Burpee, you are trained as well in mechanical engineering and joined Hydro in 1977 and went immediately to Lakeview Thermal Generating Station, and you are now Production Manager for units 1 and 2 at Lakeview.

Would you tell the Board, please, what's involved in that function?

MR. BURPEE: A. Yes. I manage the operation and maintenance of two coal-fired 300 megawatt generating units.

I have responsibility to plan, direct and control work activities associated with the day-to-day operation of those units, and I also have responsibility for business planning and budgeting for those two units. Those two units are now under rehabilitation at this time.

Q. Thank you, Mr. Burpee.

Mr. Meehan, you are Manager, Generation Planning Department, Power Systems Planning Division. You were trained in electrical engineering and joined Hydro in 1963 and almost immediately went into the Planning Engineering Branch.

Would you tell the Board, please, what's involved in your function as Manager, Generation Planning?

MR. MEEHAN: A. A large part of my job comprises obtaining the approvals to proceed with individual projects related to generation. These projects would include new generation, major rehabilitations of existing generation, and large

environmental control projects.

[10:10 a.m.]

Once a plan is established, such as the updated plan, the projects in that plan become part of Ontario Hydro's business planning process, and what my department would do is, at the right time in order to meet the in-service dates for those projects, we would proceed with the analyses, the detailed analyses and assessments and the work necessary to rationalize and to obtain Board approval if it's a major project.

Q. Thank you, Mr. Meehan.

Mr. Smith, you graduated in industrial engineering from the University of Toronto. I neglected to ask you this before, your CV says that from 1968 to 1970 you were Systems Analyst, Computer Branch, was that with Hydro or someplace else?

MR. SMITH: A. No, that was with Ontario Hydro.

Q. In any event, in 1970 to 1979 you were in the Controllers Division?

A. Yes.

Q. And in the process obtained an MBA from York in 1982; correct?

A. Yes, that's right.

Q. You join the Fuels Division in 1980

and are now the Director of Fuels, Supply and Services Branch; correct?

A. Yes. We just had a reorganization, we now have a branch that's called Procurement and Power System Planning Branch, but the Fuels Division is part of that branch.

Q. And you are now the Director of Fuels Division?

A. Yes, I am.

Q. Could you just tell the Board, please, what is involved in your function as Director of the Fuels Division, please?

A. I guess it's best described as what the Fuels Division does, I am responsible for the division. Very briefly, we are responsible for the purchase and delivery of all the fuels used at our generating stations, that involves making contractual arrangements for several years ahead for the various supplies and, if necessary, for long-term supply arrangements. And other than that, essentially we are there to advise the organization on future price and availability of various fueling options.

Q. Thank you Mr. Smith.

Mr. Shalaby, since you have been quiet so far, would you undertake, please, just to outline for

the Board in general terms the topics which we propose to cover in evidence in this Panel 8.

MR. SHALABY: A. I guess we want to add to what the Board has already heard. The Board has heard about subjects like forecasting, existing system, planning concepts, I know this seems like ages ago now. The other options that the Board has heard about were demand management, non-utility generation, hydraulic options and purchases from other utilities.

The purpose of this panel is to add to these options a description of the fossil technology and fossil options, and also a description of other options that we group under the name of alternative energy sources, they include such technologies as solar power and wood as a source of generating electricity.

So, our purpose really here is to add to the package of options that the Board has already heard about in the areas of fossil and alternatives.

Q. You mentioned the fossil options, in the context what constitutes and option and generally what are the options which this panel will be discussing?

A. When we speak of a fossil option, we speak of a fuel, a fuel as part of the option, we speak of a conversion process, it's a process that will take

that fuel and convert it into electricity. We will discuss that.

We speak of an environmentalist control package, a package that would make the conversion environmentally acceptable, so that is also part of the option. And any of those conversion processes and environmental controls come in different sizes and configuration, that is also a component of an option. And finally, that package all put together is used in a particular system application.

So those five features, if you like, constitute an option. They are again, a fuel, a conversion process, environmental controls, the configuration and size and the system application.

We will focus in providing characteristics of several new technology options in the area of alternatives, as well as fossil options that could be used for meeting future electricity demand, and they come in various arrangements that the panelists will describe to the Board.

Q. All right. and with respect to Exhibit 452, which is the 1992 update, would you outline for us how that will affect this panel's testimony?

A. The update, Exhibit 452, emphasized

things that we will pick up on in this panel and dwell on, for example, the area of anticipating future environmental regulations. We will describe our understanding of current environmental regulations and constraints within which all options have to operate, and we will also state our understanding of possible future environmental constraints that could come down during the planning period.

We will emphasize the plans that Ontario Hydro is exploring in the area of life management and life extension of some of our fossil facilities. Again, that is a key component of the plan update that we will give some attention to in our testimony, life extension and life management.

Finally, we will describe the characteristics of new fossil options but we will scale back in the areas of siting, for example, and things to do with site-specific, since we are not seeking any approvals for new fossil options. So we will describe the options but not go into details of siting.

MR. HOWARD: Perhaps, Mr. Chairman, I could give a quick road map so that everybody will know where we are going as to the specific topics which each witness will address.

We propose that Dr. Effer will start by

outlining the environmental issues. Mr. Meehan and Mr. Burpee will describe the existing fossil stations in general terms and what they are required to do in their role, and they will elaborate on the plans for the existing stations. Mr. Dawson will then provide a description of the options which are dealt with at some length in Exhibit 3, the Demand/Supply Plan. Then Mr. Burpee will talk about some of the operational aspects of those options. Mr. Smith will deal with fuel-related issues. Then we will come back to Dr. Effer for the environmental and health issues arising out of those new options. And Mr. Meehan will discuss the life cycle costs for these new options.

Then we propose, as Mr. Shalaby indicated, that Mr. Shalaby and Mr. Dawson will describe six alternative technologies briefly, and Dr. Effer will deal with the environmental impacts of those alternative energy technologies, and then we will have a grand conclusion which will be very short.

Q. So if I may then start, Dr. Effer, would you begin by telling us what the environmental issues are which you will be discussing?

DR. EFFER: A. Environmental considerations are one of several factors which taken together help Ontario Hydro to site, design and operate

our generating station facilities and the associated major equipment.

I am going to describe six of the main environmental issues which we believe Ontario Hydro should be addressing, and these are acid rain, the greenhouse effect, ozone, air toxics, discharges to water, and solid waste management.

As Mr. Howard said, I will discuss the environmental effects of fossil fuel combustion and several fossil fuel options and alternate energy later.

The environmental effects of the total fuel cycle are discussed in Exhibit 468 and elsewhere, but I will be emphasizing in my presentation the production, the generating part of the environmental effects.

Q. Are each of these six environmental issues which you are going to speak to localized in the sense that they are confined to Ontario's boundaries?

A. Not by any means. Each of them has its own particular characteristics. For example, acid rain and the ozone have effects that extend beyond the borders of Ontario and into the North American continent.

On the other hand, global effects are seen from emissions of carbon dioxide, the greenhouse

effect. Air toxics made act locally but are now being seen as affecting more distant water bodies due to long range transport and discharges to water and solid waste generally do have more localized effects.

Q. Dr. Effer, at Ontario Hydro is it your view that the environmental issues you are about to talk about can be managed by simply conforming to existing regulations?

[10:24 a.m.]

A. Not entirely. The existing regulations go a good deal of the way to providing the framework for managing environmental issues. However, some issues are emerging ones, and so there are currently no comprehensive regulations.

We have Exhibits 19, 21 and 256. These are environmental performance reports which have included statements on Hydro's policies about this matter, and they can be briefly summarized as that we do focus on emerging environmental issues, we carry out research and development and other work to find the best means to meet expected new requirements, cooperate with regulatory agencies to ensure that information is exchanged to develop a sound and rational basis for the new regulations, and we attempt to find technical means for meeting or going beyond the applicable laws and

regulations.

Finally, where no regulations exist we attempt to keep environmental effects as low as reasonably achievable.

Q. Could you just summarize for the Board before we come to the particular issues what is said in the Demand/Supply Plan Update, Exhibit 452, with respect to these matters, about regulation?

A. We made an assumption that requirement for environmental controls will in future become more stringent, and in our update we have made a statement saying that in support of our planning position Ontario Hydro will anticipate and act in advance of future environmental regulations.

Q. All right. Then, if we could come specifically to acid rain, first of all would you begin by telling us what is acid rain and how is it produced?

A. Burning of fossil fuels produces two gaseous acidic by-products to varying degrees, sulphur dioxide and nitrogen dioxides.

After emission these two gases are transformed in the atmosphere to sulphuric and nitric acids, and these acids can be brought down to earth in rain, snow, fog - that's called wet deposition; or as solid acidic compounds, or even the original dry gas,

which is known as dry deposition.

The term "acid rain" became a popular name for this phenomenon because it was believed originally that the acids were primarily brought to earth in the form of rain. However, in some situations dry deposition may be more important; for example, in areas close to a large point source.

Q. What are the main effects of these depositions?

A. The effects of acid rain have been well researched, and they are briefly that acid rain has been shown to have adverse effects on fresh water lakes, making them so acidic that fish and other aquatic organisms fail to reproduce.

Acid deposition to some soils can make them more acidic and increase the rate of leaching of essential mineral nutrients, and acid deposition has been shown to be a contributing factor to a lowered rate of growth of forest and other tree growth and also has caused tree damage in certain circumstances.

In urban areas acid deposition has been shown to cause increased corrosion and erosion to stone, concrete, plastics and metals, and there has been some concern for health-related matters associated with the desolving of metals from piping in domestic

water supplies.

An additional health concern has been that the acidic aerosols derived from emissions of acid gases contribute to aerosol formation in densely urbanized areas, and these have been related to increased hospital admissions amongst those members of the population having respiratory ailments.

Q. I want to come to some sources.

Mr. Chairman, I have with some trepidation a separate package, hard copy of overheads for each of these witnesses, adding to the numbers of exhibits but not to the bulk. Frankly, we couldn't get them into one package in time, but if we could have a separate exhibit number for this first package of overheads, which Dr. Effer will speak to, I would be obliged.

THE REGISTRAR: That next exhibit number, Mr. Chairman, is 470.

---EXHIBIT NO. 470: Overheads slides of Dr. Effer.

MR. HOWARD: Q. Now, Dr. Effer, as I indicated, we would like to have some background about sources of sulphur dioxide and nitrogen dioxides.

Can we now use the familiar NOx, N-O-small-x, instead of nitrogen dioxides? Is that general in the...

DR. EFFER: A. That would be appropriate.

Q. All right. Would you tell us something about emission sources in Ontario of sulphur dioxides and NOxs with the use of your first overhead?

A. As the first overhead, E1, shows, this Ministry of the Environment information for 1988 gives in the form of a pie diagram the distribution of sulphur dioxides emissions by sectors within the province.

It can be seen that smelters contribute very slightly over half of those emissions; utilities, which is by far the greatest contributor of that, in fact, possibly 100 per cent of that sector is Ontario Hydro, and it contributes close to a quarter, 20 to 25 per cent of the emissions; and other sources contribute the remainder.

Q. Then NOxs on E2 of Exhibit 470?

A. In E2 we have the again Ministry of Environment data for 1991 publication showing the 1988 Ontario emissions which shows that by sector the automobile is very close to contributing half of the NOx emissions; other transportation produces about 16 per cent; and utilities are contributing about 15 per cent. Miscellaneous environmental sources can range

from everything from your gas station to bakeries to beer manufacturers, a whole range of sources there.

Q. Can we take it from that that Ontario Hydro contributes in the order of 20 per cent to the acidic deposition in Ontario?

A. No. This isn't an appropriate interpretation. There are numerous sources, local and distant, which contribute to the acid deposition in one particular location. So no one single source contributes in most cases to anything more than a very small fraction of the total deposition over an extended period at one location.

As E3 shows in relationship to what we have done in several modelling exercises, we have taken the sources, many, many, probably over a hundred sources throughout North America and modelled the flow of the sulphur oxide and sulphate deposition locations, and we have taken a sensitive area in Ontario, the Muskoka Lake area, as the final repository of some of these to find out what actually occurs at one particular location.

We find that U.S. sources contribute to slightly over between 50 and 60 per cent generally of the acid deposition falling in this sensitive area of Ontario; other Canadian sources about a quarter;

background sources - that's the ambient $SO_{2}$ level, natural occurring sources; and Ontario Hydro contributes about 6 per cent of that acid deposition due to sulphate falling in Muskoka.

Q. All right. Can we come now to the regulations in Ontario with respect to acid gas emissions, please?

A. Back in 1985, the federal government and seven eastern Canadian provinces reached agreement to reduce sulphur dioxide emissions to achieve an overall reduction from Eastern Canada of 50 per cent.

Ontario's contribution has been to reduce its acid gas emissions by 60 per cent from its 1984 base year. Within the Province of Ontario four major sulphur dioxide emitters, three smelters and Ontario Hydro, were each placed under their own individual regulation.

The provincial regulation governing Hydro's emissions required a step-wise reduction, progressive reduction of acid gas emissions from a 1982 peak of 531,000 megagrams eventually to a 1994 emission limit of 215,000 megagrams.

Q. You use the phrase megagrams. How does that relate to tonnes, which we see on E4?

A. We can say that that megagram is the

same as a tonne...virtually? Yes, it's virtually.

The regulation itself places emissions on the total of sulphur dioxide and nitrogen oxide emissions and also within that includes a specific upper limit to sulphur dioxide alone.

Q. Is that the Ontario regulation 281/87 which we see--

A. That is correct.

Q. --in E4 of Exhibit 470?

A. Our overhead, E4, shows what I have described as the progressive reduction of emissions from... And then shows how Hydro has currently performed in relationship to that regulation.

You'll note that the hatched parts show that the limits, the SO(2) amounts, and the unhatched parts of each bar is the nitrogen oxides emissions. So 430,000 tonnes is our first step which we have successfully stayed under, and 370,000 of that was sulphur dioxide.

We are now entering the '91-'93 phase where we have to stay below 280,000 megagrams, of which no more than 240,000 megagrams has got to be sulphur dioxide.

And then beyond 1994 we come to the final step of 215 megagrams, of which no more than 175 is to

be $SO_2$ emissions.

Q. Is there anything in the regulation that relates these discharges to future increases in electricity demand?

A. I don't believe there is anything specific, but it is agreed that the 1994 limit is to be maintained irrespective of future increases in the electricity demand.

The regulation recognizes that acid rain is a regional problem rather than a local one and to this end has set limits for the releases from the whole system, not for individual stations or for individual units within those stations.

Q. Is there anything in the regulation with respect to the means by which the limits are to be met?

A. No, there is nothing in the regulation. We adopt the means by which we meet those limits. There are no means stated in the regulation.

[10:40 a.m.]

Mr. Meehan will discuss the range or portfolio of options that Hydro is using to meet these limits and, in particular, what is being planned for the existing generating stations.

Q. All right, can we come now to ozone.

Would you give us a description of what it is and how it's produced?

A. Ozone is a gas which is found in both the lower and upper atmospheres. In the lower atmosphere or troposphere, which extends to between six and twelve miles above the earth's surface, ozone can be produced by a number of mechanisms. Ground level ozone can be increased by drawing down from the upper atmosphere, ozone from the upper atmosphere by atmospheric disturbances. Even vegetation emits organic compounds that can enter into atmospheric reactions to produce ozone.

Thunder storms and lightening produce ozone, and finally man made NOx and volatile organic compounds, which in future I will call VOCs --

Q. First of all, tell us what they are. Volatile organic compounds?

A. By definition an organic compound is one containing carbon and these volatile organic compounds are relatively small molecules which are relatively easily vapourized and quite reactive in getting into reactions in the atmosphere.

So NOx and VOC interact with the natural atmospheric processes in atmospheric processes to increase ozone levels.

This ozone which is produced in the lower atmosphere is quite damaging to natural and man made parts of the earth, it can be damaging to plants, health and materials.

The upper ozone layer that is produced in the upper atmosphere, or stratosphere, is considered to be a good thing and the loss of that means that the sun's damaging ultraviolet rays can get through to the earth's surface more readily, and depletion of that ozone is not a desirable thing.

We have very stable chemicals such as chlorofluorocarbons which migrate slowly up into the atmosphere, and through into the stratosphere, reacting with this ozone thereby depleting the ozone layer and allowing this harmful radiation to penetrate to the earth's surface.

Q. I take it from what you have told us that ozone isn't a product of fossil fuel combustion. Why is it a matter of concern to Ontario Hydro?

A. When we burn coal and oil and even gas in the boiler, the nitrogen in the atmosphere in the air used and in the coal and oil reacts with oxygen to form NOx's, nitrogen oxides, and these then on being emitted to the atmosphere can react with VOCs under the influence of sunlight to produce ozone and several more

complex compounds to contribute to the production of urban smog.

In Ontario the rate of reaction between NOx and these VOCs and sunlight to produce ozone is controlled by both the levels of nitrogen oxide or the levels of VOC. We believe in Ontario, however, that NOx is the one of the two types of compound which is actually controlling the rate of production of ozone.

So, in other words, although Hydro's stations do not produce ozone directly, we do emit gases that combine to produce ozone.

Q. You mentioned a moment ago that this lower level ozone can have damaging effects on the environmental, would you just amplify that for us, what kind of effects?

A. Firstly, elevated ozone levels can be damaging to human health; for example, there is research showing that exposure to relatively high concentrations of ozone can affect biochemical pathways, morphology of the tissues and lung function.

At lower concentrations eye irritation, lowered physical performance has been recorded.

Q. Are we talking about smog?

A. We are talking of both ozone and in special urban situations smog can be produced as well.

Smog is essentially another compound called PAN, P-A-N for short, which is peroxyacetylnitrate is one of the predominant compounds in that urban smog.

Q. We have given the reporter one list. I don't think whatever that was is on it, but we will give it to you. P-A-N for short.

Then can we come now to the contributions of ozone production in Ontario in summary form, please?

A. May I just briefly say that ozone, prior to the answer to the other question, it's very damaging to vegetation, that's both ozone and smog, and there is a vast amount of literature on damage to crops, leafy vegetables and evergreen trees, and these reduce growth rates which can be economically quite significant. And in the urban environment ozone and smog in the urban area can attack textiles, rubber, plastics, paint. So it's quite a damaging compound.

Q. Right. Now can we come to a summary of the sources, the main contributors to ozone in Ontario?

A. In refer back to overhead E2, in respect to the acid rain concern we have gone through the NOx emissions, but now we will show overhead E5, which again is 1991 Ministry of the Environment data, and it covers the 1988 distribution of VOC emissions by

sectors within Ontario.

The predominant sector is miscellaneous area sources. They, again, can be a huge variety of small sources within the province. The main identifiable sector is vehicles which contribute about a third of the VOC emissions. Ontario Hydro's emissions are extremely small and are contained in that sector called others.

Q. All right. Can we make an estimate of how much Ontario Hydro contributes to the ozone problem in Ontario?

A. As I have said before, we contribute about 15, 20 per cent of the provincial NOx. And the two main contractors to high ozone levels are transboundary flows from the south and the automobile.

It's very difficult to determine actually what one particular sector's contribution to ozone is, because it's influenced by the location, meteorology and general weather conditions. However, given these variables, we believe that our contribution may be in the order of about 10 per cent, although we have no specific studies to verify this figure.

Q. What regulations relate to ozone production by Hydro in Ontario?

A. The provincial Regulation 308

indirectly limits ozone production by laying down ambient air quality criteria several emissions to air, and Ontario Hydro designs its station to meet these criteria, particularly for NOx.

Ontario's Clean Air Program which proposes amendments to Regulation 308 may eventually also limit more extensively nitrogen oxide emissions, NOx emissions.

In addition, of course, as I said before, Regulation 281 limits nitrogen oxide emissions by virtue of the fact that its controlled as an acid gas contributor.

Q. Can you tell us what other initiatives are being taken to reduce ozone production in Ontario?

A. In 1988 the Canadian Council of Ministers for the Environment asked the provinces to develop a program to control ozone, particularly in heavily populated areas, and one area which they wanted some specific attention was on the Windsor-Quebec corridor.

With respect to this work Ontario Hydro has been contracting through the Canadian Electrical Association, and our work within the association arrived at a management plan which we presented to the

Canadian Council of Ministers of the Environment. We emphasized control options rather than setting specific emission rates from generating stations. The Canadian Council accepted this position in 1990 and then requested the provinces to prepare separate emission control plans and targets.

Within Ontario the plan is to reduce nitric oxide emissions from the base line year of 1985 by 25 per cent. Ontario Hydro has targeted a 40 per cent reduction of NOx, and that is based on the 1985 base year and the target is aimed for the year 2000.

Again, Mr. Meehan will discuss the range of options Hydro will be adopting to meet the regulations and these new targets.

Q. All right. The third issue you indicated you were going to deal with was the greenhouse effect. Would you just describe briefly for us what is included within the phrase of "greenhouse effect"?

A. The earth's temperature is maintained within a fairly narrow range by a layer of gases and water vapour which allows the sun's heat and its radiation to enter the earth's atmosphere, but prevents some of this heat from being back-radiated into space. This phenomenon is very similar to how the glass in a

greenhouse behaves, hence the name "greenhouse effect".

Without this layer of gases surrounding the earth, the earth's temperature would be about 35 degrees colder than it now is.

What we should really more strictly call the enhanced greenhouse effect is largely due to the progressive build up of some greenhouse gases such as carbon dioxide produced largely by the combustion of large amounts of fossil fuel such as coal, oil, gas and wood.

Taken altogether, other gases contribute about the same greenhouse effect as carbon dioxide, and these include methane which comes from a wide variety of sources, farm animals, termites, rice paddies, garbage dumps, mines, wetlands.

We also have nitrous oxide, another greenhouse gas, which comes from fossil fuel combustion and also heavily fertilized farm land.

Man made compounds such as CFCs which are used as refrigerants and solvents also contribute, and also ozone which we have mentioned.

Q. Now, Exhibit 40 is a paper done in 1989 at Hydro, a task force on the greenhouse effect. But would you just tell us briefly, if you can, how far science has progressed in understanding and getting

some consensus on this phenomenon?

A. A vast amount of research has already being done and many of the scientists are still debating about what is fact and what is conjecture.

I think the only universally accepted fact is that carbon dioxide concentrations are increasing in the atmosphere at a rate that would lead to a doubling, that's relative to pre-industrialized days, doubling by the middle of the next century.

A little less certain is the widely known fact among scientists that the earth's temperature has increased by half a degree Celsius in the last hundred years. This increase is more or less consistent with what a lot of the global warming models are predicting, but we have not been able to decide whether there is an actual cause/effect relationship between the CO(2) increase already measured and global warming.

[10:55 a.m.]

A great deal of the funding and effort on the greenhouse effect is being spent on modelling, and these are extremely complex operations. They are attempting to simulate the processes that are going on in the atmosphere, and the early ones were - in spite of being rather complex - simplistic insofar as they didn't reflect a good range of the phenomena that are

naturally occurring on the globe.

These earlier models predicted global temperature increases of between 1-1/2 and 4-1/2 degrees celsius due to CO(2) doubling. But as the models have become more sophisticated they are including the effects of oceans and the effects of clouds and certain biological processes, whether it is coincidence or not, I don't know, but the more recent predictions of global warming have tended to be in the lower range, lower end of this range of temperature increases.

The warming models are being used to predict effects such as ice disappearance and subsequent increases in sea levels, large regional changes in precipitation patterns with the ensuing effects on forests and other vegetation.

The timing and severity of such effects very much depends on the predictive accuracy of the global warming models. Still very much further down the line in having firm information are discussions on the socioeconomic effects of global warming.

No direct human health effects due to increased concentrations appear to have been claimed at the moment, but if global warming occurs longer-term effects on human health can be predicted based on these

physical changes in the earth's climate.

Q. How is Hydro involved in the production of greenhouse gases aside from what you have already told us?

A. Hydro has generated approximately a quarter of its electricity in 1989 from the burning of coal and a small amount of oil, and therefore contributes to the global emissions of carbon dioxide. Within Ontario -- again, this is overhead E6, and its source is 1991 data from the Ministry of the Environment.

The 1987 emissions by sector show that the main emitter is industry, in a general sense a third; the transportation sector takes up 28, close to 30 per cent CO(2) emissions; Ontario Hydro and the utilities provides 20 per cent of its emissions.

And incidentally, that translates to about 0.41 per cent of global carbon dioxide emissions. That's Hydro's emissions.

Q. All right. Can you just summarize for us what is being done nationally and internationally with respect to these greenhouse gases?

A. As far as I am aware, there are no known regulations specifically limiting greenhouse gases.

The changing atmosphere conference in Toronto in 1988 set a goal of 20 per cent reduction in carbon dioxide emissions by 2005. That goal was proposed.

A federal/provincial task force has been set up following this conference to review the various options available to meet it, meet the goal, and to find out what kind of costs and other effects the implementation of such reductions would mean to Canada's economy.

Since then there have been numerous conferences where attempts have been made to reach agreement on global reductions and binding agreements have not yet been reached. Many countries have issued targets, there are plans for emission reduction, and several cities have also contributed their own targets, including Toronto and Vancouver.

There is still some expectation that the UN conference in Brazil in 1992, that's this year, will see the signing of a climate change convention.

Q. Dr. Effer, is there enough information currently available so that one can estimate the likely impacts on Hydro's operations of this phenomenon?

A. Several of the climate change models

have predicted that precipitation in Ontario will decline, and so that decline, if it were to occur, would have an effect on our hydroelectric generation predominantly.

This has been extensively discussed in Exhibit 40, which is a task force on greenhouse effect.

An additional effect on Ontario Hydro's operation would be that the warming would cause a reduced demand for electricity in winter and, due to the air-conditioning load, an increased demand in the summer, and we believe the net annual influence of these two opposing effects would be to slightly increase the energy requirement within the province.

Within the generating station itself there will be small decreases in efficiency. The cooling water for condensing the steam in the station would be less cool, and also the actual transmission of the electricity would be influenced somewhat by increased temperatures. So these two factors would reduce electrical efficiency and would have to be made up by increased generation.

Q. Assuming that in the future there may be regulations mandating reductions what changes could Hydro make?

A. We have talked about Exhibit 40,

which looked at the various options available to Hydro to contribute to a reduction in the carbon dioxide emissions, and if we were to be placed under such controls our long-term planning could include such elements as increasing our demand management even further, improving energy conversion in existing plants, promoting cogeneration further, giving preference to electricity generation from renewable sources such as hydroelectric, maintaining a reliable nuclear component in the generating mix, more use of fossil fuels within the fossil stations that yield less CO(2) per amount of energy produced, and we would also be including the consideration of new technologies which have been shown to have improved energy conversion from coal.

Q. All right. Then, could we turn now to the fourth topic you indicated you were going to discuss; namely, air toxics? First of all, what are air toxics and how are they are produced?

A. Hazardous air toxics are defined by the regulators as pollutants which are "known or suspected to pose a risk to human health or the environment".

Toxic trace elements are present naturally in coal and oil and can be released in their

elemental form or in combination with other materials on combustion and can either be released separately into the atmosphere or in association with fly ash particles.

During combustion other elements or compounds in the coal may react with each other to form organic compounds, and these are toxic, and these are also released in a vapour form or again absorbed onto fly ash particles.

Q. Again, are these localized concerns, near to a station?

A. We considered them originally to be a fairly localized concern insofar as they were emitted as the main gases and considered them to be a localized air quality. However, more recent concerns relate to their longer range transport and deposition into water bodies where they enter food chains.

Q. Now, could you just identify the compounds which are concerned from fossil fuel combustion, and would you give us the chemical designation as well as the english description?

A. Again, being a natural product, coal and to a lesser extent oil have a wide range of trace elements, but the principal elements that we are concerned with mostly are arsenic, beryllium, cadmium,

chromium, lead, nickel, and selenium.

We have in addition to trace elements, organic compounds, we mentioned VOCs, and those are principally acetone and formaldehyde.

Then we have a group of organic compounds called polyaromatic hydrocarbons.

Q. What's the short form for polyaromatic hydrocarbons?

A. PAH. And then benzo(a)pyrene is a principal component in that group of compounds.

Then we have a series of compounds that react with chlorine, organochlorine compounds, the principal ones being PCBs and dioxins.

Q. Can you tell us then the state of regulation in Ontario with respect to air toxic emissions?

A. Our existing provincial Regulation 308 sets air quality standards for a large number of elements and compounds, which include air toxics.

A new source for any of these pollutants must apply to the Ministry of Environment for a certificate of approval using the prescribed Regulation 308 models to calculate ground level concentration and thereby demonstrate compliance.

In the future we are expecting the

amendments to Regulation 308, this is popularly known as the Clean Air Program, and one of the main objectives of this amended regulation is to control the emissions of trace inorganic and organic contaminants.

The regulator will determine the level of hazard for each of these contaminants based on its toxicity, its persistence, and whether it biocumulates in organisms.

Based on these classifications, the contaminant would then be placed in one of three levels of control, and several contaminants even though the amendments are in the preliminary stages have already been assigned the strictest level of control.

I should mention that the U.S. Clean Air Act, which was passed last year, also has sections in it which specifically address release of air toxins.

Q. And what's going on in Ontario Hydro to address this environmental concern?

A. We have carried out emission testing programs at our Lambton Generating Station in 1989 and previously to that Lakeview in 1986. A summary report of these programs have been provided in some detail in response to some interrogatories.

These programs cover stack testing of trace elements and trace organics. In addition, and

again in response to interrogatories, we have listed trace elements that have been measured at Nanticoke Generating Station under a research program supported by the Canadian Electrical Association.

Q. Anything else?

A. Ontario Hydro is participating in an American study called PISCES, P-I-S-C-E-S for short; for long, it is Power Plant Integrated Systems: Chemical Emissions Studies.

This is essentially a program which will trace the fate of the production of chemicals within the process streams of fossil plants, and it is expected that these results will enable utilities and regulators to make good decisions made on the best scientific and technical information available.

We have also within Ontario Hydro initiated a program called Integrated Air Management Strategy in which risk assessments will be included and will include air toxics.

Thirdly, there is a study being carried out on air toxics and general health effects and centred on Lakeview Generating Station. The results of this are not yet available.

Q. At this stage can you help as to the potential effects of air toxic emission from Ontario

Hydro's plants?

A. I refer to Exhibit 468, which concludes that the effects of air toxic emissions from a large coal burning station, and with the assumption that the scrubbers on that coal burning station do not remove any air toxics, these emissions will fall well within the acceptable risk criteria as set down by regulatory agencies, such as the Environmental Protection Agency in the United States.

Q. When the regulations are developed further is there any way to reduce air toxic emissions from a fossil station?

A. We expect that the updated program, which includes upgrading electrostatic precipitators in some of the stations, will considerably improve releases of the air toxics, those which are associated with particulates, and we also anticipate that the wet scrubbers that we are putting in at Lambton Generating Station will take out some air toxics, but these removal efficiencies are not well defined.

Q. All right. We will come to those ESPs and wet scrubbers later on.

The fifth item you indicated you were going to deal with was discharges to water. Could you describe for us what are your concerns there, please?

A. There are two main concerns. One is the thermal discharges to water and its effects, and the other one is the discharges of chemical contaminants.

Q. Let's deal first with thermal discharges. What do you mean by that?

A. Both fossil and nuclear fuel generating stations rely on the steam cycle for producing electricity, and the residual heat in the steam and the steam of condensation is transferred to the cooling water flowing through the condensers.

In our generating stations the effect of this transfer of heat to the cooling water is to raise the discharge by various levels, depending on the design of the station, by about 11 to 17 degrees Celsius. It is then discharged back into the water body. This is known as once-through cooling.

The plentiful supply of cold water in Ontario has influenced Hydro to locate its thermal and nuclear stations on the shores of Great Lakes, with one exception, using the once-through cooling technology.

Q. And what concerns arise from this once-through cooling technology?

A. There are four main concerns, and they are biological, aquatic biology concerns, I guess.

[11:15 a.m.]

In the overhead E7 you will see the idealized diagram which has been modified from a Maryland Department of Natural Resources diagram.

Q. Now before you go on, would you just tell us what you mean by the four divisions entrapment, impingement, entrainment and discharge effects. I guess beginning with entrapment.

A. When we go through the diagram we see that the entrapment of organism refers to the fact that larger organisms such as fish will come into the cooling water tunnel or channel and not be able to escape from that area, so that they are unable to return to the water body; in other words, they are going to be entrapped and they are going to be finishing up on the screens shown on the diagrams.

Q. Impingement?

A. Impingement is that, the loss of organisms by impingement on the screens and the travelling racks of the generating station.

Q. Then entrainment?

A. Entrainment refers to the effects on smaller organism such as plankton and fish larvae which are small enough to go through the screens and go through the pump and condenser tubes, and are exposed

to temperature, mechanical and pressure changes during their passage before they arrive at the discharge canal.

I should say there is additional stress on some of our stations because we have a high temperature rise across the condensers and in order to meet regulatory agencies' discharge limits, we have to temper the water by bringing in cooling water and bypassing the system, adding it to the discharge canal. This also in turn has effects on entrained fish and other organism.

Q. Is that what is shown at the bottom of E7 call tempering pumps?

A. That's tempering pumps, yes.

Q. Then discharge effects?

A. The discharge effects refer to the effects of the temperature primarily and flow to some extent, and the effects on fish and bottom living organisms in the near field of the thermal discharge or thermal plume as we call it.

Mobile organisms such as fish are attracted by the heated discharge and also the smaller organisms which have survived passage through the plant are exposed to a certain period of time at elevated temperatures.

Q. Has any work been done to attempt to assess the environmental effects of this once-through cooling system?

A. Yes. In the 1970s there was a very, very large amount of research done on the effects of once-through cooling, and Ontario Hydro also carried out a large research program called Biological Investigations to Improve Once-Through Cooling System Designs for the Great Lakes, and this has been referred to in response to an interrogatory.

The results of this extensive program which included field programs extending over three to four years has lead to innovative designs of intakes and discharge structures for the protection of the aquatic environment.

At operating stations we continue to monitoring aquatic environmental parameters such as temperature, suspended solids and amounts and types of fish killed, and we report these reports regularly to the Ministry of the Environment. These results show no specific problems encountered in the last several years.

Q. Can you outline for us the design changes that have taken place as a result of this research you have described?

A. Our earlier designs such as Lakeview, Pickering and Lambton were once-through cooling systems with intakes at the shoreline and discharges at near or close to the shoreline, discharges at the surface of the lake. They were not very effective in minimizing fish entrainment or temperature impacts.

We have done a fairly large number of changes but culminating in our Darlington Generating Station we think we have a cooling water system which represents the state-of-the-art. Here we have both a submerged intake and a submerged discharge, and I believe Mr. Dawson will go into more detail on this. But the biological effect of this submerged intake has been that the flow velocities of water going through the plant is such that it will alert fish to know that there has been a change in water direction, and we anticipate that fish intake will be markedly reduced.

The discharge is also a submerged one, again Mr. Dawson will be describing this. The principal effect from a biological point of view is to reduce the temperature of the water very rapidly so that the effects on fish, particularly what we have identified as fall spawning species in the Darlington area will not be affected during the winter.

We expect that this design will be

adopted with any new generating stations.

Q. Then the second concern you indicated about discharges to the water were chemical discharges. What is involved in that?

A. We use the Great Lakes water for many operations in the power plant and we have got to maintain and improve that quality by limiting discharges of organic and inorganic contaminants.

Q. Can you just list for us the main sources of possible chemical contaminant from a coal-fired plant?

A. Well, not specifically a contaminant. The once-through cooling system of course is the main water volume involved, but we have much smaller volumes such as the water treatment plant, drains from the yards and the floors within the plant, sewage treatment where present also emits discharges, fly and bottom ash ponds, coal pile drainage and when we install scrubbers there will be some small discharges.

Q. Then what kind of pollutants are we talking about here?

A. The conventional pollutants are acids, alkalis, suspended solids, dissolved solid, and oils and greases. And we have the more toxic or persistent pollutants such as metal, phenols, and

chlorinated hydrocarbons.

Q. All right. Again can you tell us what the regulations are in Ontario with respect to these matters?

A. There are quite a number, the principal regulation is the Ontario Water Resources Act which controls the taking of the water and pollution of the discharged water. We have to have permits both for the taking and discharges of this water.

Under this Act water quality objectives and guidelines for a wide range of pollutants have been set in order to protect ground and surface waters.

A second provincial statute, the Environmental Protection Act contains various provisions for controlling water pollution.

Under the federal Fisheries Act there are also guidelines in the regulation related to water quality for the protection of fish.

For many years Environment Canada has cooperated with industry in developing a series of codes of practice covering each phrase of a generating station, right from siting, design, operation, right through to the decommissioning phase, and these codes have reflected the federal government's concern by strongly emphasizing the opportunities during each of

the phases of the lifecycle of a generating station for adopting water use and water pollution control improvements.

Environmental Canada has been actively participating in reviewing our environmental assessments under the provincial Environmental Assessment Act during the flue gas desulphurization program, and has been emphasizing the importance of conforming to the provisions of these codes of practice.

On the international level is the Great Lakes Water Quality Agreement between Canada and the United States which again identifies areas and objectives for water quality improvement.

Q. What steps are currently under way with respect to this kind of chemical discharges to water?

A. The provincial government has got a very active initiative called the MISA program, M-I-S-A, which stands for Municipal Industrial Strategy for abatement. I will call it MISA in future. This program is driving the most of our current activities in controlling emissions to water.

The main objective of this MISA program is to reach virtual elimination of the persistent toxic

elements from all discharges to Ontario's receiving water, and other industries have already been going through this same exercise as Ontario Hydro in meeting the provincial Ministry's requirements.

Ontario Hydro itself has completed the first phase of the program leading to the preparation of an effluent monitoring regulation, that's the final point for the electric power generating sector.

The first phase of this was to monitor flows and composition of selected water effluents from Hydro's fossil, nuclear and hydroelectric stations. And the second phase has now started and includes identification of the control, integration and treatment options which are economically achievable, and which we can make available -- find available to adopt in order to meet effluent limits.

The next phase extending from this year, 1992, to 1996 will be the design, engineering and construction of systems needed to meet the agreed effluent limits.

Q. What sort of steps can be taken in an effort to minimize these releases in future stations?

A. The MISA regulations will be applied to upgrading existing stations and will obviously be of extreme value in feeding into our engineering design of

future stations. This will allow us to incorporate much more advanced and integrated ways of treating our waste water discharges and possibly at a much lower cost than the changes that we are having to be incorporating into existing generating stations.

MR. HOWARD: Mr. Chairman, we are now about to start on the sixth and final element,if this a good time.

THE CHAIRMAN: All right. We will break for 15 minutes.

THE REGISTRAR: Please come to order. The hearing will recess for 15 minutes.

---Recess at 11:30 a.m.

---On resuming at 11:50 a.m.

THE REGISTRAR: Please come to order. This hearing is resumed. Please be seated.

MR. HOWARD: Q. Dr. Effer, the final issue you indicated you wished to speak to was the issue of solid waste in the environment. What are the major solid wastes produced by Hydro's fossil stations?

DR. EFFER: A. The principal solid waste is ash from the coal burning, and this comprises the bottom ash which falls to the bottom of the boiler, that's about 20 per cent of the total weight, and the flyash which is the smaller particles from coal

combustion and that's about 80 per cent of the total weight of ash.

In the future we will have flue gas desulphurization waste which will be essentially gypsum, and we also have now smaller quantities of wastes such as oil, flyash and construction garbage.

Q. Are any of these among the hazardous wastes as defined?

A. Yes. Overhead E8 which is taken from Regulation 309 and is used to classify wastes into various levels of toxicity is shown here on this overhead. In the left-hand column there are several elements and also one organic compound, group of compounds, PCBs. The first column is essentially the level of each of these elements, analysis of the leachate, and it's a standard leaching test on the ash.

Q. When you are speaking of leachate, what do you mean by that?

A. The ash is contacted with water and it's essentially in a column and the water is falling from the column, at the bottom of the column, when it's dissolved, the soluble material is called the leachate.

Q. Okay. Sorry, I interrupted you.

A. In schedule 4, that first column of numbers is essentially the drinking water standards.

In order to relate these various leachates to that figure, the second column shows that if you can achieve less than 10 times that concentration in the left-hand column for every one of those elements, the metal element and PCBs, you can then call your waste non-registerable, and that means that it doesn't have to meet any further requirements under Regulation 309.

However, moving to the second column, if your leachate by analysis contains 10 to 100 times the concentration of any one of those elements, then it falls into the category of registerable, in that case there are limitations to the use that that waste can be put and deposited.

The final column is if any of the elements exceed 100 times the level in the left-hand column, then the waste is termed leachate toxic and again much more stringent control measures have to be adopted for that.

Q. Now, can you tell us how that applies to the existing stations?

A. We have conducted leach tests on ash from Lakeview, Lambton, Nanticoke, Thunder Bay and Atikokan. We find that coal flyash is not hazardous as determined by this regulation and therefore it's classified as a non-registerable waste. However, it

cannot at the moment be entirely -- it cannot be used for a wide variety of things, including lake filling, because it falls short of some of the other Ministry of Environment's requirements. There is one requirement called the Decommissioning Guidelines which the leachate test fails.

The oil flyash that I mentioned as being a minor quantity of solid waste has high levels of some metal constituents and therefore is classified as toxic under Regulation 309 and has to be disposed of in a registered and contained landfill site.

We anticipate that flue gas desulphurization waste will be classified as non-hazardous under this Regulation 309 procedure.

Q. As non-hazardous it would be, as I understand it, under this EA non-registerable; is that correct?

A. That is correct, yes.

Q. Then what are the uses of flyash?

A. There have been uses of flyash in highway and berm construction. The ash from Lakeview is being used in cement manufacturing. Flyash is also being used in asphalt mixtures, and experimentally it's being considered as soil modifier in agriculture. We have looked at this within Hydro and we are looking to

field tests now.

Ontario Hydro's research has shown that when we add a small amount of cement to flyash it reduces the level of contaminants in the leachate and this research was done to try and find out if cement-stabilized flyash could be used as a lake fill.
[12:00 p.m.]

Again, field tests are still in progress on this work.

Q. You mentioned the flue gas desulphurization by-product that would be becoming available. What are the potential uses for that?

A. The primary purpose which we expect to have for the gypsum, calcium sulphate by-product is in commercial use of the gypsum, possibly -- well, mostly in the wallboard manufacturing. FGD waste is also being used for hazardous waste stabilization and, again experimentally, as a soil additive.

Q. Now, then, are there any other regulations which you can summarize concerning ash management?

A. There are no other regulations, but the Ontario government has made solid waste reduction a high priority in its programs.

Within Ontario Hydro we have set a goal

of 50 per cent utilization of flyash by the year 2000, and we established this target last year. At present, this is an internal target and I believe not included in the Ministry of the Environment's waste diversion targets because disposal of the majority of our flyash is on site.

In order to achieve the 50 per cent target a utilization program has been proposed. The main elements of this program are continued ash utilization and marketing from our fossil stations for cement manufacturing in Ontario and in use in U.S.A. for synthetic aggregate.

Other work programs under way for using flyash include a quality assurance and quality control program, and we are also using it, small uses of flyash for constructing berms and for waste stabilization.

Q. Then having dealt with those six issues would you summarize how they impact on Ontario Hydro's fossil generation station and their use?

A. I tried to review the main environmental issues and there are obviously others.

We are spending a great deal of effort, not only now, but in the past, on investigating environmental matters, and this effort will increase in the future, especially on emerging issues, and I think

this is largely due to several factors.

One is that society itself has shown increased environmental awareness, and I think there is a willingness within society to devote more resources on resolving environmental questions.

Within Ontario Hydro this has certainly led to a continuing and growing effort to meet more stringent regulatory requirements, and also, I think this has been prompted also by putting a greater corporate emphasis on environmental leadership.

Q. Thank you, Dr. Effer. Let's shift, if we may.

Mr. Meehan, you were going to, as I indicated -- perhaps, Mr. Chairman, could we have the overheads which Mr. Meehan is going to refer to as the next exhibit?

THE REGISTRAR: That will be number 471, Mr. Chairman.

THE CHAIRMAN: Thank you.

---EXHIBIT NO. 471: Mr. Meehan's overheads.

MR. HOWARD: Q. Mr. Meehan, a short form of the topic I described is system requirements. Could you give us a brief outline of the role of fossil and what you propose to talk about under this business of system requirements?

MR. MEEHAN: A. Yes. I am going to explain that there are three basic roles that generation can assume in meeting system requirements, and I will indicate that fossil options can meet all three of those roles, and that fossil options are flexible and can adapt to changing demands that the system may put on them.

I will explain what attributes are important for each role. I will then go on to discuss the existing fossil generating system and explain the important role that we see for fossil options in the future.

Finally, I will introduced the process by which new options are examined, and that is the thermal cost review option and the alternative energy review option.

Q. Just to start --

A. Process, I'm sorry.

Q. Sorry?

A. I used the word "option" and I should have been explaining the "process": the thermal cost review process, and the alternative energy review process.

Q. All right. Can we start with M1, your overhead, which locates the stations which have

already been named and a couple of others, just so we can get this all in context?

A. Yes. The idea of this overhead, M1, is to remind the Board where the generating stations are, and I will talk a little bit about the size of them, et cetera.

I will start on the left-hand side with Atikokan Generating Station. It's our smallest generating station. It comprises a single, 200-megawatt unit. It's also our newest generating station. It burns lignite from Saskatchewan.

At Thunder Bay Generating Station there are two 150-megawatt units. They also burn lignite from Saskatchewan. At that station there is also a 100-megawatt unit, and it was designed to burn U.S. coal. It is currently in mothballs right now, and I will explain later in my discussion what the word "mothballs" means.

In Southwestern Ontario, starting with Lambton, near Sarnia, Lambton Generating Station comprises four 500-megawatt generating units, and it burns U.S. coal.

J. Clark Keith Generating Station comprises four 60-megawatt units, and it is designed to burn U.S. coal. It is currently mothballed. It's one

of our older stations.

Nanticoke Generating Station comprises four 500-megawatt units. I believe the Board toured that facility. It is burning U.S. bituminous coal, and it has a blending facility there that I will talk a bit about later, and we can blend other coal with the U.S. coal.

At Lakeview, located in Toronto or Mississauga, rather, there are eight 300-megawatt units that burn U.S. coal.

Hearn Generating Station comprises four 100-megawatt units and four 200-megawatt units, and that station is currently mothballed.

On the far right we have Lennox Generating Station. That comprises four 500-megawatt units, and it is designed to burn residual oil.

Q. Now, I know that the concept of system requirements was discussed on Panel 2, but would you just run through it again for us quickly?

A. Yes. System requirements are the demands that are placed on the generating system by our customers. I would like to remind the Board by showing two figures that are found on page 3-23 in the DSP report, which is Exhibit 3.

This overhead, identified as M2, depicts

the total system load in each hour for a whole year. The scale as such that each day there with 24 hours on it appears almost as a vertical line.

I believe it was Panel 2 that depicted similar information in their testimony, but they referred to a one-week period. I am using a whole year here because I will be talking about annual capacity factors and annual load factors. So each hour of the year is represented on that figure, and it goes from winter through summer to winter again.

This next figure, M3, is called the Load Duration Curve, and it is obtained by taking --

Q. It comes from the DSP, too, and that reference on the bottom right-hand corner gives the reference in Exhibit 3; does it?

A. Yes, it does.

Q. All right. Thank you.

A. It is obtained by taking the hour-by-hour loads that you saw in the previous figure and rearranging them in order, starting with the highest and ending with the lowest.

You can see from the figure that there is a minimum level of demand that must be met at all times on the right-hand side, and there is a peak level of demand that occurs for only a short period.

The demands can be identified as base, intermediate, and peak, and they are on that figure.

Base load refers to load that occurs between 70 and 100 per cent of the hours in the year; peak load has been defined to be that that occurs from zero per cent of the time to 20 per cent of the time; and intermediate load is that that lies between 20 per cent of the time and 70 per cent of the time.

The generating options that operate within these load categories fulfill three separate roles which can require that they have different technical, operating and economic characteristics.

Q. All right. Then, what sort of demands do these different requirements place on the generating system? Can you summarize that for us?

A. Well, no one generating option has all the characteristics that best meet the needs of all three roles, and because our generating system is large we can have different types of generation for each role, and the right mix of that helps reduce the cost.

In addition, options that have the flexibility to meet a wider range of demands or can adapt to different circumstances are of particular value.

Some of the important characteristics for

these three roles are shown in this figure which is identified as M4.

I would like to take you down the column that's identified as "Base", and talk about the requirements that are to the left of that column.

A base load generating unit, or one that is suitable for base load, would be one that is suitable for high utilization. It doesn't need to have a large number of starts and stops because most of the time it is working, and it doesn't have to be too manoeuvrable. It can be loaded up and held at high load for long periods of time.

On the far right of the overhead, under the column "Peak", just about the opposite characteristics are true for a unit that is suitable for peak generation. Its utilization is generally low, it can be held in a contingency situation and not even operated and yet serve good purpose. The number of starts and stops can be high, and it can be manoeuvred rapidly to meet changing demands.

The intermediate generation has requirements that fall between those two.

Q. All right. Then, you have indicated that fossil can meet all of these roles. Obviously not every fossil option can. Can you amplify that a little

bit for us?

A. Each fossil option has technical characteristics and economic advantages that make it more suitable for one of these roles than the others. Some options are expensive to build and yet they will have low running costs, so that if they are operated for long periods of time they can overcome the disadvantage of a high capital cost because their low running costs are in fact displacing higher costs from other options on the system.

For example, conventional steam cycle, which is similar to the Nanticoke Generating Station. It utilizes coal that has a relatively low fueling cost although it has a high capital cost to build.

That type of generation is economically suitable then for base and intermediate applications, and they are also technically suitable because they are large and they are slow to start and they are less manoeuvrable. So they are economically as well as technically better for that high intermediate or base load role.

On the other hand, oil-fueled combustion turbine units have low capital costs and high fueling costs. Economically they are more suitable for base load applications. They are also technically suitable

because they can be loaded and unloaded quickly.

For example, a combustion turbine unit can be started and shut down within an hour, whereas a conventional steam cycle unit may take up to 12 hours from the time you start starting it up.

Q. All right. Then, what about the environmental control equipment in these three roles?

A. Environmental equipment like generating equipment have capital costs and they have running costs. Environmental control equipment that has high capital costs are most suitable for addition to generating units that are operated for long periods of time or base load units. High capital cost equipment that is installed on peaking units can render that unit uneconomic.

Q. When you are at the planning stage, Mr. Meehan, how sure can you be of the role that a station is going to be called upon to meet?

A. We are not too certain at all. In the planning process we do the best we can to select the options that are most suitable for the forecast requirements. In reality, however, after the unit is put into service it will serve whatever purpose the system demands of it at that time.

This is where the versatility and the

flexibility of options comes in.

During the life of an option the demands on it do change. Changing circumstances can change the utilization of fossil stations. They may be pushed from base load towards peak load, or they may have been planned as peak load generation and find themselves meeting demands that are more in the base load area.

Fuel cost changes can result in changes to the utilization of an option. Fossil generation that can use different fuels or that can change fuels is also a benefit.

Another consideration is changing environmental regulations. This may have an effect on the day-to-day dispatch of the unit or could result in different ACFs, annual capacity factors, and/or the need for environmental control equipment.

Of course, a big influence is our customers and how they utilize their electricity. If they utilize more electricity in the off-peak time than we thought they might or less in the on-peak or vice versa, then the role on these generating stations would change.

The history of our Lennox Generating Station is an interesting example.

Q. Can you just amplify that, explain

how Lennox is a good example of versatility?

A. It's a good example in both the changes in a planning situation and in an operating situation.

The initial plan for Lennox in the late 1960s was that it comprise a four by 500-megawatt coal-fired station, and we expected it to be utilized in an intermediate to base load use.

[12:20 p.m.]

In 1969 the plan was revised so the station would use oil, residual oil, and the expected utilization was the same. Cheap oil was predicted to be available for the life of the station. There were also increasing concerns for air quality and fuel diversity which favoured the change to oil.

The station went into service in the mid-70s, just as the high cost of oil relative to coal occurred, and the station then went into a peaking role for a short while.

By 1980 oil costs are soared and load growth was declining so that Lennox wasn't needed. It became economic to mothball the station and this was done by 1982.

Q. You told us you were going to give us a short description of what is involved in mothballing,

is this a good time?

A. It would be an ideal time, I think.

Mothballing is a term that we use when generating units are placed out-of-service in a manner which protects them from rapid deterioration. If we did nothing to them they would rust and destroy themselves ultimately, so we protect them.

It's usually done to units that are obsolete or have high running costs, as in the case of Lennox the running costs were high, and we do this sometimes rather than decommissioning or taking a unit out-of-service.

In the late 1980s it became economic to return Lennox to service, load growth was high again and the reliability of the system needed support, but oil costs have continued to remain high and the station is being utilized in a peaking role and has annual capacity factors of about 5 to 10 per cent.

Currently, Lennox is being considered for conversion to burn natural gas as well as oil, and the cost of gas and the environmental implications will be factors that are considered in that decision. We expect to make that later this year.

Q. Can you give us any other examples of how stations have changed roles?

A. Well, when Hearn and Keith were constructed in the 1950s, these are the two stations that are in mothballs right now, they were initially run at base load until larger fossil and nuclear units were added. These larger units were better suited for base load application and consequently Hearn and Keith moved towards serving a peak role.

The change in role of Keith and Hearn also served to illustrate another point, and that is the development of technology. It was their efficiency along with their size which made newer fossil units more economic and this contributed to them being used less. Finally, when the demands were low they were relegated to reserve and then ultimately mothballed.

Q. Now then, can we just look at the current system as to how much fossil there is used in the current system.

A. This figure overhead M5 shows the installed capacity in 1993. Hydro will have a total installed capacity of 32.5 gigawatts by 1993, and this includes all types of generation. About 11.9 gigawatts, or 37 per cent, is fossil generation. It's provided by 28 generating units that are located at the six operating generating stations that I showed on my first slide with the exclusion of Keith and Hearn.

The note at the bottom of the pie indicates that of the 11.9 gigawatts, coal comprises 9.4 gigawatts, and that's 29 per cent of the entire pie, and it is 79 per cent of our fossil generation. 79 per cent of our fossil generation is coal-fueled, the other 2.5 gigawatts is oil-fueled and most of that comes from Lennox Generating Station, .3 gigawatts is from combustion turbine units.

As I have mentioned Hearn and Keith are already mothballed and they comprise a total 1,450 megawatts of generation.

Q. All right. Can you just briefly describe for the Board what the current role of fossil is and how the system demands and other factors are influencing that role today?

A. Currently our operating fossil stations are being used in a range from peaking to high intermediate. Nanticoke and Lambton are operating in the high intermediate range. These are the two work horses on the system.

Station use is higher than we originally expected, and the running costs for the stations are about what we expected relative to other options.

The reason they are working a little harder than we expected isn't because of their costs;

it's because we are having lower than expected availabilities of some other generating stations on our system, and that's causing them to run at higher annual capacity factors.

Lakeview is operating in the low intermediate range, very close to peaking, station use is close to what we would expect, although here it's very difficult to predict the utilization for this type of duty. Lambton and Nanticoke are both run ahead of Lakeview in their dispatching order because they are more efficient and Lakeview therefore sees the demands that the system places on it to a greater extent than Nanticoke and Lambton.

Lennox I mentioned is operating as a peaking station because of its high fuel costs, and they are considerably higher than when we planned the station. Atikokan and the two units at Thunder Bay are operating at close to base load. These are smaller units and they are located on Ontario Hydro's west system and their operation depends on the availability of the hydroelectric generation in that area and upon the load which depends on economic conditions, et cetera.

Hearn, Keith and Thunder Bay Unit 1 are mothballed, and they are considered capacity reserve.

The mothballed units would require several years to bring back into service.

Q. Just in general terms, how long is it expected that existing fossil generation is going to last and how is that determined?

A. The service life is one of many things that is considered when it's decided to build a generating facility. This initial service life reflects the industry experience or, if there is no experience, the expectation of the industry.

The initial specified life for all our existing coal-fired generating stations was 30 years, and that remained the assumption until 1981.

Q. Then what happened?

A. For many years the retirement of generation didn't play a role in planning new generation, it didn't determine the need date because it was so far in the future. Hydroelectric generation, for example, is known to have long life times and generally this didn't affect the need date. So it wasn't until the generating units that were installed in the 1950s, when their 30-year life was coming due, that it caused a concern in the planning of new generation. So, the question of lifetime became the subject of serious review in the late 1970s.

In 1981 the average service life of Nanticoke and Lambton was increased to 35 years on the basis of operating experience and the expectation that pollution abatement devices would be economically feasible if they were required. All other operating stations remained at 30 year life.

Q. And after that?

A. In 1985 for planning purposes the timing for new generation started to be based on the assumption that all operating fossil generating stations had an average service life of 40 years. This was based on consideration of the physical condition of the plant, the environmental requirements that we might run into, and economic operation and future need.

The assumed life of 40 years for fossil stations is what is used in the 1989 Demand/Supply Plan.

Q. What are the assumptions used in the 1992 update?

A. This overhead identified as M6 shows the fossil station retirements assumed in 1984 prior to the first change, and what was assumed --

Q. That's the upper line we see?

A. That's the upper line there. That's the amount of generation that we had assumed prior to

1984, in 1984 and prior to that.

The line in the middle indicates the amount of generation that was assumed in the Demand/Supply Plan. And the amount of retirements now assumed in the update of the Demand/Supply Plan is shown as the dotted line near the bottom of the curve.

Based on this current assumption there is 4,300 megawatts of existing fossil generation which was assumed to retire in the Demand/Supply Plan that is not assumed to retire in the update to that plan.

Q. Just looking at M6 then in Exhibit 471, when is the first change? In what year is the first change between the retirements that are in the DSP and the retirements that are in the update?

If I read this thing correctly, it's 2008?

A. 2009 actually would be the way it would be used in the models.

Q. All right. So that what kind of a change is this from a planning perspective?

A. It's not a big change or it's not a small change.

The 4,300 megawatts of new capacity that isn't needed now at the end of the period is a large amount of generation and so that is a big change.

On the other hand, the initial need date for new generation might be deferred one year by this change, and that's not too significant particularly because it is already so far into the future, it being 2009.

Q. Can you just amplify that for me. You are talking about the need date for new generation by one year. How do we see that, is that illustrated in M6?

A. This is what we were just talking about. If we assume that we would replace existing generation because of its retirement with new generation, and you are comparing the original Demand/Supply Plan and the updated plan, there is no change that would occur for that single reason until 2009.

Q. We know that in the update the phrase "life extension" is used. We are going to deal with it at some length, but what are the main issues with respect to this concept of life extension?

A. The issues relate to whether it is technically, economically feasible, and whether it is environmentally acceptable.

We have known for many years that it would be technically feasible to extend the lives

beyond 40 years. We weren't confident about whether it would be economic or environmentally acceptable.

Q. And the $64 question is: What has changed since 1989, Mr. Meehan?

A. Three things have changed. We have gained considerably more information from the inspections performed for the Lakeview rehabilitation and the Nanticoke life management program which give us more confidence in knowing the costs and the economics of life management and therefore life extension.

The industry is also tending more towards life management and extension.

The second thing is that the planning environment has changed. There have been major changes to other assumptions that provide the opportunity to consider the question without extreme consequences. We have the next year or two to make sure life extension is the path that we want to take. We didn't have that luxury before.

The third thing that has changed is the extent of Hydro's willingness to anticipate rather than wait for environmental regulation. Hydro is now indicating what control equipment it thinks would be appropriate if plants are life extended.

Q. Then can we talk for a few moments

about the future role of fossil. First, how is it intended to use existing fossil generation?

A. We expect our fossil generation to serve us in the future just as it has in the past. The system is versatile and changing system requirements will continue to cause the utilization of the fossil generation to change.

Lambton and Nanticoke will continue to be the system work horses, and the other generation will be utilized just as it has in the past.

Q. All right. We have been talking about existing. What type of new fossil generation would be considered for building in the future if there were to be a need for new fossil generation?

A. This figure, which is identified as M7, and it has been taken from the 1989 Demand/Supply Plan, page 14-8, the figure number there is 14-2.

Q. Sorry, is there an error there? It's figure 14-8 in the bottom right-hand corner?

A. It's on page 14-8, and I believe the figure number is 14-2.

Q. Okay. Sorry, I misheard heard you.

A. It also lists nuclear generation and purchases at the bottom of the page. I am talking about the ten options that are identified at the top

part of the figure.

It outlines there the configuration, by that I mean the number and the size of the units primarily; the primary energy, which is the fuel source, and what is identified there as the principal system application which I have been referring to as its role.

Q. Basically how many concepts are there in these ten options, generation concepts?

A. There are five generation concepts that are identified there.

The conventional steam cycle, again which is like Nanticoke, like most of our generation, fossil generation.

Q. That's options 1, 2 and 3?

A. Yes.

Q. I think in the original DSP the shading was a different colour; is that correct?

A. Options 1, 2, and 3 are the conventional steam cycle options.

Combustion turbine units are the second concept that's shown there, and they are options 4 and 5.

Combined-cycle units which combines the combustion turbine unit to a steam cycle, which Mr.

Dawson is going to talk about later, they are options 6 and 7, and they have different roles, there is a peaking combined-cycle and an intermediate combined-cycle identified there.

If we could back up a moment to the options 4 and 5, the difference there is in the fuel, one is oil and one is gas.

One of the newer technologies, integrated gasification combined-cycle is option 8 and it is option 9, and that may be a little confusing on that figure.

The difference in those is the way we have phased one of them, phased the construction of one of them, which is option 8, and in option 9 we build the whole thing at one time. Again, Mr. Dawson will talk about this, but the phasing is that you start with combustion turbine units, you make that simple system into a combined-cycle system, and then you add the coal gasification as a third phase to that. The unphased one is that you build it from scratch, all at the same time.

Q. And the final option, 10.

A. Option 10 is the atmospheric fluidized bed combustion technology.

Q. How are those ten options studied in

the demand/supply selection?

A. They were selected on the basis of primary and secondary criteria for evaluating and developing the recommended plans that are contained in the demand/supply planning strategy, which is Exhibit 74. Those options, they cover well-established generation concepts as I have mentioned, and there are the two that are less proven clean coal technologies.

Q. Which are those two?

A. The IGCC and the AFBC.

[12:40 p.m.]

Q. Then, since I know we are going to come to it, is there a role for alternative energy options, which we are going to discuss later on in the future planning?

A. There may well be a role for the alternative energy options. The main barrier at present is their high cost, but in some of the cases that we will hear about this may change considerably over the next decade or so.

Q. You indicated you were going to summarize for us the processes for reviewing these fossil and alternative energy options. Would you do that now? How have the processes been developed?

A. Well, the fossil options have

developed through the thermal cost review process, which is something that has been going on for many years.

It wasn't until 1989, however, that as part of the demand/supply planning process that the review was done all at one time and is contained in one set of documents, which is Exhibit 35, I believe.

Generally, the same thing is true about the alternative energy technologies. There are groups within Ontario Hydro that are charged with monitoring and assessing the emerging technologies, and this has been done in an ad hoc way until this year.

Again, as part of the demand/supply planning process the information on the alternative technologies, those that appear most promising, is reported in one document, and that is Exhibit 344.

Q. All right. Then, if we can leave it there for the moment, you are going to be talking a little bit more about rehabilitation plan, which is referred to in the DSP report.

Can we turn now to Mr. Burpee, who will talk about the existing fossil stations. In particular with respect to the rehabilitation plan would you summarize the programs that are included in the rehabilitation plan in the original DSP?

I guess I better get your overheads marked. Could that be the next exhibit, Mr. Chairman?

THE REGISTRAR: The next exhibit number is 472.

---EXHIBIT NO. 472: Mr. Burpee's overheads.

MR. HOWARD: Q. The first one is a reference to the DSP figure from the Demand/Supply Plan, is it?

MR. BURPEE: A. That's correct. It's figure 10-8, which can be found on page 10-11 of the Demand/Supply Plan.

Under the centre column you can see that the Rehabilitation Plan had two major components, one being the rehabilitation of stations and the other is the installation of environmental controls to reduce acid gas emissions.

Under the rehabilitations in 1989 Hydro had specified the Lakeview and Lambton rehabs. The plans for other stations had yet to be determined.

Q. Now, have there been any changes in this Rehabilitation Plan included in the 1992 update?

A. Yes. We will be putting in place life management programs for all fossil stations instead of rehabilitations. I will talk to these changes. Mr. Meehan will talk to facilities planned to

control acid gas emission.

Q. Let's begin with rehabilitation. What is included within the term "rehabilitation"?

A. As shown in figure 10-1 on page 10-2 of the DSP report, a rehabilitation is a major reinvestment of capital to restore and improve performance.

On this panel when we use the term "rehabilitation" or "rehab" we mean work that is done in one major outage which can last anywhere from nine months to two years per unit.

Q. Can you give the Board some indication of your experience with rehabilitation at Lakeview?

A. In the early 1980s it was forecast to mothball all eight units of Lakeview by 1988. This was based on reduced load growth. Staff were gradually cut back and maintenance funding was reduced. Known problems were not addressed at that time as it did not appear to be economical to do so.

Following the unplanned shutdown of Pickering 1 and 2 in August, 1983, energy production increased but the future still remained uncertain for Lakeview. Maintenance programming did not keep up with the increased production. An example of this would be

a number of boiler problems which were not addressed.

At the same time, problems with cracking of major pressure components, became apparent both within Ontario Hydro fossil facilities and the U.S. In fact, within the U.S. there were some catastrophic steam line failures.

In 1986 it appeared that there would be a need for Lakeview to operate beyond the year 2000. At that time life assessment outages were taken to determine remaining metalurgical life of a number of components.

Q. Let me just stop you there for a minute, Mr. Burpee. You mentioned normal outages and outages. What is a life assessment outage?

A. Well, the whole purpose of the outage was not to do maintenance but was to do inspections, to go in and spot check a number of what we felt then were critical components to see what the existing metalurgical damage was and the remaining life of the component.

Q. And then you got information from that. Then what happened?

A. Then we combine known reliability problems; we review what current reliability problems we are having. We also review for potential

obsolescence problem. That's a case of where we anticipate spare parts won't be available.

There was also determined to be a need to burn low sulphur coal, which the station was not physically able to do at that time.

All these items were put together and resulted in the rehab scope.

Q. What's the basis for the decision to rehab or not?

A. It was based on a continued need for the plant and a desire to maintain the safety, reliability and environmental standards of the plant.

Q. Now, can you just summarize for us the change which you indicated from rehabilitation mode to life management mode?

A. The change in strategy is driven in part by the Lakeview and Lambton rehab experience as well as U.S. utility experience. Part of the rehab is to do inspections to assess and verify current condition and remaining life.

We always wait until we have significant deterioration in performance or if the role of the station is to be changed, such as the need for high energy production; that is, moved from a peak to an intermediate or base load.

The full cost of doing that can't be known until the inspections are done. This makes project planning for cost and scheduling difficult and requires large contingencies of time and money and may not make best use of constrained funding.

Q. What is the life management strategy? How is it different?

A. Well, life management focuses on monitoring equipment condition. We know where we are in the life of the equipment at any one time and what has to be done to achieve the desired performance of the station.

The condition of plant components are assessed on a regular basis. By having knowledge of the current condition and the required role of the plant allows for maintenance programming and possible capital reinvestment over the life of the station. All work is done to the extent possible as part of the normal planned outage program.

Q. Just to amplify that, tell us what is involved in a normal planned outage program, the third kind of outage.

A. A planned outage is essentially just a need for annual maintenance and inspections that is programmed usually at least a year or two, in fact to

some degree up to 10 years ahead of time as to what will be required on almost a routine basis as opposed to just breakdown maintenance.

Q. Then how is life management actually carried out?

A. Well, to begin with, to have a life management program requires a base line condition assessment of plant, equipment and systems.

A condition assessment is a combination of non-destructive examination of pressure components, visual inspections of electrical and rotating equipment, and some diagnostic testing of equipment in operation. The results of all this testing and examination are analyzed and we prepare a condition assessment.

Once you have done your assessment, then a decision is required, which is usually referred to as a run, repair, replace decision, where you determine the condition is fine, you can continue to run, and you decide when you will inspect next. Sometimes repairs will be required, and sometimes you might determine a need to replace the component before you can run again.

Lakeview rehab experience to date has indicated some repair has been required, especially of defects that originated back at the time of

manufacture.

Once you have done your base line assessment, from this point on you have a comprehensive inspection, a machine condition monitoring program to evaluate equipment degradation. Results are consistently reviewed and inspection frequencies adjusted to reflect current conditions and anticipated requirements.

Q. What impact does this life management strategy have on cost of running the station?

A. As we have stated in the updated DSP, there is a small increase in OM&A - that's operation, maintenance and administration costs - due to the cost of inspections.

Q. Right. And what about maintenance costs?

A. Well, if the station is meeting its required role and life is consumed at an appropriate, rate then no change in the maintenance program is required; therefore, no change in maintenance costs.

If life is being used faster than anticipated and we have to look at a number of strategies, we can change how we operate the plant, we can increase maintenance and OM&A, or we can plan on a capital replacement as the end of component life

approaches. We would adopt the strategy that resulted in the best net present value.

Total lifetime costs of OM&A and capital are expected to be lower.

Q. What are the benefits that are perceived for life management?

A. Life management will give us flexibility in managing the facilities. We will be able to make better decisions on where and when to spend money for the best payback and results. Better assessment on the impact on a station and required funding if the role is to be changed is another result. In other words, if we know where we are and we know what is required we will have a better idea of what it will cost to get there.

All work is done within the planned outage program, as stated, and in this case it will mean the units are available for winter peak demands.

We will constantly be able to evaluate the cost of achieving performance results. We will have better control of reliability and efficiency, which will also yield cost savings.

Q. Where in the system are life management programs being implemented?

A. The intention is for all fossil

stations to have life management programs.

The most notable program in development at this time is at Nanticoke where base line assessments are under way. This will be the starting point, as I've said, from which we will compare condition assessments in the future. Nanticoke was given priority as it is the oldest non-rehab station.

The rehab inspections will provide base line assessments for both Lakeview and Lambton. These base line assessments are the key elements in extending the service lives of Lambton and Nanticoke.

Q. All right. And then how does life management strategy fit into the concept of life extension that we were talking about?

A. By having knowledge of the condition of the units it permits a better estimate of the cost of meeting new requirements, such as going beyond the 40-year life. Otherwise, to make that decision major inspections with long outage requirements would be required to determine if it was economic to keep the units running.

Q. What is required if you are going to keep the station operating beyond the nominal 40-year life?

A. From a station perspective, life

beyond 40 years is no different than beyond 20 or 30 years.

Our strategic and business planning is done on a rolling 10-year period. The key to the process is to know the requirements of the plant. By that I mean energy production, reliability, efficiency and regulatory requirements and what the current condition is.

We then look at what work must be done to meet the requirements. This process goes on no matter what the age of the plant is.

Q. Can you assist us with what other utilities are doing today?

A. A number of utilities plan on a life of at least 50 years for their fossil stations. Decisions on retiring units are economic as the technological life of the station is virtually indefinite.

Now, mind you, the components themselves have a finite life, but they can be replaced for a cost similar to meeting new environmental regulations. When the costs, when all these costs make the station uneconomical to run in comparison to other sources of supply it is retired.

Q. Do I take it from this that there

is -- let me ask it the other way. Is there a practical life to a fossil station?

A. As stated by Mr. Meehan earlier, the DSP used a 40-year service life.

Earlier stations were once thought to have a 30-year life. This was based on an assumption that fossil technology would advance to such a degree in terms of efficiency that the older plants would be uneconomical in comparison.

I would like to point out that a conventional steam cycle plant that is considered in the thermal cost review would operate at about the same temperature and pressure as our oldest operating units, which are 30 years old.

Given no substantial improvement in cycle efficiency and the cost of building new stations, continued service beyond 40 years is technically feasible and has potential to be economically feasible.

MR. HOWARD: We are about to turn to a new topic, sir. Is this a good time?

THE CHAIRMAN: Yes, it is. We will adjourn until 2:30.

THE REGISTRAR: Please come to order. This hearing will adjourn until 2:30.

---Lunch recess at 12:56 p.m.

---On resuming at 2:30 p.m.

THE CHAIRMAN: This hearing is again in session, please be seated.

MR. HOWARD: Q. Mr. Meehan, can I turn to you now. This morning we heard from Dr. Effer about the control of the acid gas emissions, sulphur dioxide and nitrogen dioxide. Could you outline for us Hydro's approach in reducing acid gas emissions?

MR. MEEHAN: A. Ontario Hydro's policy with respect to the environment was discussed by Panel 2, and Dr. Effer has already indicated the numerous regulations which require Hydro's compliance.

What I will be discussing now deals only with SO(2) and NOx, and the facilities being installed and the measures that we are taking to control those emissions.

Q. Can you summarize that approach to begin with?

A. First of all, it is explained in chapter 7 of the plan analysis report, which is Exhibit 6.

What we do first is that we endeavour to achieve the reductions in a cost-effective manner, and the overall nature of the regulation that Dr. Effer explained is such that a program approach is most

suitable. The approach we are taking to control acid gas emissions over the long term is to have available a range of options and to put in place the most appropriate ones at the right time as and when they are required.

To summarize, as summarized on page 10-6 of the DSP report, which is Exhibit 3, the control options can be divided into the four broad categories shown on this overhead, M8. We can reduce the fossil use and we can do that by more demand management, non-utility generation, or non-fossil generation which might include alternative technologies; we can reduce the sulphur content in the fuels by shifting to a lower sulphur coal or use of natural gas; we can develop clean coal technologies such as the IGCC or the integrated coal gasification combined cycle, or the AFBC, the atmospheric fluidized bed combustion technologies, and the fourth thing we can do is we can install emission control technologies on our existing or on any new facility that we might built.

Q. Has there been any change in this program?

A. The basic approach is the same but there are two things that have happened recently that are likely to influence the measures we take and the

equipment we install.

As Dr. Effer has already mentioned, Ontario Hydro has recently targeted on reducing NOx emissions by the year 2000 by 40 per cent from 1985 levels. This is based on the need to reduce NOx as a summer smog precursor rather than an acid gas. The second thing is that as a result of planning to extend the lives of some coal-fueled generation, acid gas control facilities may be installed sooner than required to meet existing regulations. These considerations are included in the updated plan.

Q. We will come back to them in a minute. But first can you tell the Board what measures have been taken to -- what has already been installed first with respect to sulphur dioxide?

A. This figure identified as overhead M9, you saw this one this morning when Dr. Effer was speaking. I have added to it the 1991 emissions.

It shows the regulated limit and the reductions we have achieved so far. The reductions shown include the effect of reduced coal use and the use of lower sulphur fuels. Those are the only two things that we have done so far.

The facilities that have been installed which assist in the reduction of SO(2) emissions

include coal blending facilities at Nanticoke which were installed in 1979, so they were installed prior to anything you see in that figure, at a cost of $44 million, and we have installed flue gas conditioning equipment at Nanticoke and at Lambton at a cost of $34 million at Lambton and $47 million at Nanticoke, and it became fully operational in 1991.

Q. What is the purpose of the flue gas conditioners?

A. Flue gas conditioners don't remove SO(2) from the flue gas per se. What they do is permit a station to effectively burn lower sulphur coal than it was designed to burn.

Q. Why was it chosen to install flue gas conditioners?

A. Well, for example, Nanticoke was designed to burn 2-1/2 per cent sulphur coal and it has flexibility to perform reasonably well down to 1.1 per cent sulphur level without flue gas conditioning.

When the sulphur levels get below 1.1 per cent in the coal, the electrostatic precipitators are unable to capture sufficient flyash and the flue gas opacity regulations would be exceeded unless we reduce the output of the generators.

Flue gas conditioners optimize the

electrical resistivity of the flyash, so the electrostatic precipitators can capture more flyash while burning low sulphur coal thus permitting the full generator output without exceeding opacity regulations.

Q. And as to the future, are any facilities committed to remove sulphur dioxide?

A. Two flue gas desulphurization scrubbers are under construction at Lambton for service in 1994. They will cost $537 million. These scrubbers will actually remove SO(2) from the flue gas.

Now how scrubbers operate will be explained a little later by Mr. Dawson.

Q. How is it you expect the Lambton units to be operated once they are fitted with the first pair of scrubbers?

A. It is expected that these units would be operated at high capacity factor. They would have the lowest SO(2) emissions for each unit of energy produced from Hydro's coal stations, and we expect it would be economic to load these unit heavily since the coal to be used will be less expensive than other coal on the system.

Q. Is there anything else being done?

A. We are doing preliminary work now to use natural gas at Lennox, and this, besides providing

fuel diversity, would provide the potential to reduce SO(2). We have only committed the study at this time and if we decide to proceed, the decision to construction natural gas facilities would be made in the fall of this year.

Q. All right. Anything else?

A. As we have already discussed, the update assumes that Nanticoke and Lambton is life extended beyond 40 years.

The update also assumes that these stations would have scrubbers retrofitted on all units at Nanticoke and Lambton by year 40. This is consistent with our view that if existing coal generation were replaced with new coal generation, it would include scrubbers.

However, there is a question now and that is, once you have decided to extend the life of specific plants, should you wait until year 40 before adding scrubbers, or is there good reason for adding them a little sooner. And the updated plan assumes the scrubbers would be added before year 40. This accommodates an orderly installation program and it provides environmental benefits.

Q. So far we have been talking about sulphur dioxide. What about NOx?

A. We have installed low NOx burners in the late 1980s at Nanticoke on all eight units at a cost of $12 million. This is one combustion process modification that we have made, and I will use that expression a little later. The NOx emissions at Nanticoke are reduced about 35 per cent by that modification.

Q. What else is being done with respect to NOx emissions?

A. We have not modified any other equipment so far but we are doing preliminary work at Lambton with respect to combustion process modifications again which are specified to reduce NOx about 35 per cent. This work is scheduled to be committed this year at a cost of about $100 million.

As I mentioned earlier, Hydro has targeted to reduce NOx 40 per cent by the year 2000 from 1985 levels.

For after the year 2000 we intend to maintain our emissions at or below that new level, and to ensure this and to be able to respond to possible additional ambient ozone requirements, which is smog, we have initiated studies to determine the need and the technical feasibility and the most cost-effective method of further reducing our NOx emissions and

subsequent ambient ozone levels. To this end Hydro is getting under way a full scale urea injection demonstration on one of its coal-fired units, and a pilot scale selective catalytic reduction technology demonstration. As I have just indicated for scrubbers, the updated plan assumes that selective catalytic reduction or some equivalent reduction technology for reducing NOx would be installed on the units that are life extended. Again, the question is, should we wait until the units are 40 years old, or is there good reason for adding them sooner.

The update assumes SCRs, selective catalytic reduction devices, would be added before year 40 on the Nanticoke and Lambton units. And again this accommodates an orderly installation program and provides environmental benefits.

In addition to this, the updated plan assumes that combustion process modifications would be installed at other fossil generating stations.

Q. You have mentioned it a couple of times, can you amplify why it is that you are not immediately installing the best available technology as soon as possible?

A. Well, the simple answer to this is that we try to balance the need for environmental

protection against the cost and the need for an orderly installation program.

Our practice with respect to this balance has been changing toward a greater emphasis on environmental protection. This figure which is identified as overhead M10 shows the SO(2) and NOx emission control facilities included in 1989 Demand/Supply Plan and in the 1992 update.

In the 1989, the original Demand/Supply Plan, the number of scrubbers for reducing SO(2), the number was four, and they were to be installed at Lambton, in the updated plan the number is twelve, and that would be the four Lambton units and the eight Nanticoke units.

For NOx combustion process modifications are being made on fourteen units, instead of eight, and selective catalytic reduction, or SCR, is being included on twelve units whereas none were included in the 1989 Demand/Supply Plan.

Q. All right. We will get some more amplification now. We will turn to Mr. Dawson who is going to deal in some detail with fossil fuel technology in the DSP and explain why they are selected.

Can I have the overhead for Mr. Dawson

marked as the next exhibit.

THE REGISTRAR: No. 473, Mr. Chairman.

THE CHAIRMAN: Thank you.

---EXHIBIT NO. 473: Mr. Dawson's Overheads.

MR. HOWARD: Q. Can you describe how you are going to go about telling us about the technology please, Mr. Dawson?

MR. DAWSON: A. Yes, I am going to describe the fossil fuel technology that is presented in the Demand/Supply Plan. I am going to explain why those particular options were selected.

In the Demand/Supply Plan on page 14-3, there are five components of an option listed, and those are on the first overhead that I have, D1, and they are referred to as primary energy or fuel energy conversion process, the environmental control, the configuration and the system application. I am going to deal with the central three of those five components and Mr. Smith will be dealing later with the fuel component and Mr. Meehan has already talked about the system application.

[2:46 p.m.]

Q. All right. As I understand it, when we were looking at that earlier figure from the DSP, you were going to discuss five technologies. Can you

summarize the five different technologies that are in the plan for us, just to remind us?

A. Yes. There is conventional steam cycle technology, which is the same technology that is in all our generating stations currently. There is combustion turbine technology, combined-cycle technology, integrated gasification combined cycle, and atmospheric fluidized bed technologies. Those are the five.

Q. Let's start with the conventional steam cycle, then.

A. Very well. As I mentioned, that is the technology that we currently use at all our major fossil fuel generating stations, including Nanticoke which I believe the Board visited some months ago.

The only difference is that on new installations there would possibly be more extensive emission control on them than is currently there, but we are planning to add quite a bit of that emission control.

Overhead D2 is a schematic diagram of that technology, and the technology can be used to burn either coal, oil or gas, and I am going to focus on the coal-fired option because that's the one that we have in the Demand/Supply Plan. It can best be used for

base or intermediate load, though it can be used for peaking if necessary.

There are five components to a conventional steam cycle, the first one being shown on the lefthand side of the overhead, and that's the fuel supply, storage and handling system.

There is a boiler, which is shown in the centre of the diagram. There is the steam turbine generator system, which is shown on the top and to the right-hand side of the diagram. There is a transformer, which is shown on the extreme right, and then there are the environmental controls and waste management systems, which are shown in the bottom of the diagram over towards the left-hand side.

The fuel storage and handling system basically for our applications would likely consist of a dock and a boat unloading system. There would be a coal storage pile that would probably hold the equivalent of about eight months' storage of coal, and that is primarily to supply the plant during the winter when boat navigation isn't possible and also to provide some contingency storage, too.

There would also be coal storage bunkers that would hold typically about a 24-hour supply of coal, so that the coal can then be fed directly to the

coal mills which grind the coal to about the size of talcum powder prior to firing it into the boiler. And connecting all that together is a conveyance system.

The delivery system may also be by rail, as it is in fact at Thunder Bay and Atikokan. So those are the two basic options that we have.

My next overhead, D3 --

Q. Your overhead is a lot more attractive than the hard copy.

A. Yes, I apologize for the hard copy.

Q. We have got a technicolour overhead.

A. That's the price you pay when you get a coloured overhead, I think.

It shows the boiler layout, and immediately below the boiler on the extreme left-hand side you can see the coal mills, the pulverizers which grind the coal to very fine size, and then it's conveyed by air and fired into the furnace at about the level of the green box, which is about a quarter of the way up the furnace.

The furnace itself is the vertical section of the boiler on the left, and that is enclosed by membrane walls which are water cooled. Then, in the upper portion of the furnace you can just see there are some pendant heat exchangers which in fact convert the

steam produced in the water walls to high temperature steam, and that then goes over to the turbine.

At the back of the -- if you could just hold on a second, Sam, there?

At the back of the boiler the almost spherical object you can see immediately behind the boiler is air pre-heater where the combustion air being taken to the coal mills and to the furnace is pre-heated with the remaining heat left in the flue gas.

And then, about the centre of the picture is the electrostatic precipitator, and that leads then to a scrubber which is on the extreme right of the stack, which removes the sulphur dioxide, and then the flue gas is returned from the scrubber to the stack.

If we can now return to the overhead D2, I will just go on to explain that the steam from the boiler in fact drives the steam turbine and produces electricity.

As we have mentioned, there are tradeoffs in terms of operating flexibility. You can use the equipment either as base load, intermediate or peaking, but there are tradeoffs between efficiency and operating flexibility that can be made in the design.

There is also, in that diagram on D2, a

condenser which in fact condenses the steam back to water which is then returned to the boiler, and the heat extracted in that process is returned to the lake through the once-through cooling system.

Q. What influence does the fuel have on boilers?

A. It can have a very big influence, and one of the factors that has that influence on design is the ash fusion temperature of the fuel; that is, the melting point of the ash.

The boiler has to be large enough to ensure that the ash is cooled to a point where it's solidified before it exits the top of the furnace and passes through the convection heat exchanger surface that I pointed out on the earlier diagram. Otherwise, the ash sticks to that surface and solidifies there and affects the heat transfer characteristics and the gas flow characteristics through the boiler.

Therefore, the furnace size is dictated by the melting characteristics, and you can see on this diagram that for a medium volatile bituminous coal in comparison to a high slagging lignite, where the biggest difference in the two fuels is the ash melting point, there is a large difference in size. The lignite boiler is roughly double the height and getting

on for over 50 per cent larger in plan area, too.

Q. The height is obviously illustrated. If I understand it correctly, the plan area or its circumference or square is shown in the top?

A. Yes, that's right. That's the plan area that is shown at the top of the elevations of the boilers, yes.

Q. All right. Well, we have got to the generator. Then, if you could just shortly describe what happens after that?

A. The transformer is the fourth step in the process, and that is common to all technologies, and I don't really intend to talk very much to it beyond here.

But it's simply a device which increases the voltage from the generator, the voltage of the electrical power supply to that of the bulk electricity system, whatever that happens to be.

Then, finally, we have the flue gas emission control system, and I will be speaking more about that later in more detail.

Q. Then, let's go back to what happens when you burn the coal. What are the by-products of coal?

A. The by-products are the ash that Dr.

Effer talked about a little bit year, two types of ash basically: bottom ash, which is the material that does in effect impinge on the furnace walls and then falls off and falls into the bottom of the boiler - it's collected there; and then the flyash, which is collected in the precipitator, which I pointed out on the earlier overhead.

We try to reuse that as much as we can. For instance, all of Lakeview's ash is recycled into the cement industry right now. Otherwise, it's landfilled, and usually landfilled at the generating station.

Q. All right. Can you give us some information about the life of combined steam cycle?

A. In the thermal cost review we estimated a life of 40 years for this technology, and that's based on our current practice and our knowledge with conventional steam cycle technology. It depends, though, very much on the actual equipment that is installed and on the actual service that that equipment sees, and until you have actually bought the equipment and have it in place and have some operating experience about it, then it's very difficult to know what the actual life will be.

Q. I think I said "combined steel

cycle". You answered conventional steam cycle.

A. Conventional, yes.

Q. "Steel cycle"? Steam cycle.

Now, then, having dealt with that, can we go to the next technology; that is, the combustion turbine units?

A. Yes. That's the same technology that essentially is used to power aircraft though industrial units, the types of units used in the utility industry, are much larger.

It has the benefit of being able to start up quickly and to be loaded rapidly, and therefore it is an ideal option for peaking. The disadvantage is that it needs clean, high-quality fuels such as oil or gas, and it tends to exhibit poor thermal efficiencies, too.

My next overhead, D5, is a schematic diagram of a combustion turbine unit. I have broken it down into seven basic components, and again we have a fuel handling and storage system. There is a compressor, there is a combustion chamber, then the gas turbine itself, which drives the generator, and again we need a transformer, and again there will be environmental control systems.

If the unit is used for intermittent

peaking, then it's likely that we would probably have a dual fueled system because it would likely be uneconomic to operate on the basis a firm gas contract. So we would likely burn gas when it was available but also have oil there as a back-up supply.

Natural gas would be delivered by pipeline and as such it doesn't need storage. The oil could be delivered by boat or rail or pipeline or truck, depending on the circumstances of the site. The storage that was required would depend on the type of delivery that was used.

The compressor, which is shown over on the left-hand side of the diagram, compresses the air and provides air for combustion purposes to the combustion chamber, and there it's mixed with the fuel and burned to produce a hot gas which is then expanded through the gas turbine, which is about the centre of the diagram. That drives the generator to produce the electricity.

Q. At this time what are the maximum outputs that might be expected or achievable from gas turbines?

A. The largest units that are currently available are about 170 megawatts per unit.

Q. And again, what would be the expected

life of this technology?

A. We have assumed a 30-year life in the thermal cost review, recognizing that the gas turbine itself sees some very severe temperatures and operates in a very severe climate, and, as a result, the replacement costs of those components tend to be very high and very frequent, and therefore we think probably a 30-year life is probably conservative.

Again, it will depend on the actual equipment and on the service that it sees. For instance, it may not run very much, and therefore it may in fact see a much longer life.

Q. All right. Now, could we turn to combined-cycle technology. Would you explain that for us, please?

A. Combined-cycle technology is again based on gas turbine technology, and the difference being that the heat is recovered from the exhaust of the gas turbine, and that is used to produce steam and drive a steam turbine. So you have a combination of a gas turbine and a steam turbine.

It is more complex. It adds about 50 per cent to the generation capacity of the gas turbine. It also improves the thermal efficiency of the process.

[3:00 p.m.]

As I said, it's more complex and therefore it tends to be less suitable for peaking and more suitable for intermediate or base load. However, it's possible to design the system so that a gas turbine can be run independently and can be used for peaking.

Overhead D6 is a schematic diagram of a combined-cycle system. I apologize, it's a little busy.

Basically what it shows is two gas turbine systems providing steam for a single steam turbine generator which is shown in the centre towards the right of the diagram.

There are six components to the system, again fuel handling and storage, which would be much the same as for the gas turbine, the gas turbine itself which we have already described, and then - and this is shown towards the centre the diagram - there would be a heat recovery steam generator, in fact there are two shown on the diagram immediately adjacent to the stack, and then a steam turbine generator which is driven by the steam produced in the heat recovery boilers, and then again a transformer.

Q. If I understand this diagram correctly, there would be three generators involved,

two directly with the CTUs and one with the steam?

A. That's right, that's the way this diagram shows it.

In fact, there are a number of alternative layouts. You could have a single steam turbine generator per gas turbine generator. But the way this one is shown is a single steam turbine driven by two gas turbine generators, that's right.

Q. Can you give us an idea of the expected life?

A. Yes. Again because of the gas turbine generator component in the system we have assumed that the life would be 30 years, though again it would depending on the actual service that it sees.

Q. All right. Now can we turn to IGCC or integrated gasification combined cycle?

A. Yes. Gasification combined cycle is a new concept, but the components themselves that go to make up this concept are not new.

Coal gasification has been practiced for well over 100 years, but it's been adapted to increase the scale and improve the economics for combined-cycle applications.

In the overhead, D7 --

Q. Do we have D7?

A. In fact, you can see a dotted line right across the centre of that diagram, and the gasification part of the technology is shown above the dotted line, and below the line is the combined-cycle technology which we have already discussed.

This technology was demonstrated by the Electric Power Research Institute of the United States a number of years ago, it's a 100 megawatt scale. It is currently operating in a Dow Chemical Plant in New Orleans at a place called Plaquemine, at a 160 megawatt scale, and there is a system currently being constructed in Holland which will operate at 250 megawatt scale.

Q. What are the attractive features of IGCC?

A. I think the main attraction is that it provides an opportunity to achieve combined-cycle efficiencies, higher efficiencies than you can get with the conventional steam cycle but using coal.

It also provides the opportunity to phase the construction and, in fact, build combustion turbines when the need is for peaking generation and as that need develops into a more of an intermediate or base load requirement you can add on the combined-cycle phase, and then ultimately if fuel prices move to the

point where it's economic, you can then add the gasification phase.

So it adds flexibility in terms of fueling strategy.

Q. Can you give us just a short description of how this technologies works from fuel handling on?

A. Yes. There are eight basic components: Fuel handling, oxygen separation, the coal gasification process itself, gas cooling, gas clean up, there is a combined-cycle plant, there is a transformer and then there is emission control and waste management.

Since coal is the fuel then the coal handling system would be essentially the same as we have described for conventional steam cycle.

The oxygen separation is required for the gasifier in order to get a high enough heating value gas to operate the gas turbines, but that's conventional commercial technology and so I won't go into a detailed description of that.

The gasification itself is essentially burning the fuel with a limited amount of oxygen, so that rather than converting it to carbon dioxide, it is converted to carbon monoxide with some hydrogen in

there too, and then that gas can later be burned in the gas turbine.

The gas is then cooled with a heat recovery system prior to cleaning the gas, and that's the reason it's cooled is because you need to cool it in order to clean the sulphur dioxide and the particulate out of the gas. And the cooled gas is then scrubbed with a water scrubber to remove particulates, and then with an organic solvent which selectively removes hydrogen sulphide which is a form of the sulphur in the gas, and that can remove about 98 per cent of the sulphur that's available in the fuel gas.

The gas is then burned in the combustion chamber of the combined-cycle plant and from there on the description is essentially the same as the combined-cycle plant that I described earlier.

Again, because it relies on gas turbine technology we have assumed a 30-year life for that option.

Q. Then the fifth option that's looked at in the plan is atmospheric fluidized bed. Can you describe that for us?

A. Yes. Atmospheric fluidized bed technology, one of the benefits of it is that it has the flexibility to burn a range of solid fuels and it's

able to do that because it achieves long residence times for the fuel particle within the combustion zone of the boiler. It's useful as a base or intermediate load application much the same way that conventional steam cycle would be, and it is particularly useful if you have a number of low cost and low grade solid fuels available as fuel.

It essentially has the same components as conventional steam cycle technology and it is shown on overhead D8. The only difference is the combustion technology itself, and that's shown within the boiler which is roughly in the centre of the overhead. And I think that's best described, if you can imagine a bed of granulated limestone which is supported on a perforated plate, and the combustion air is directed underneath that plate, that is as it passes through the plate it has sufficient pressure to lift the limestone bed off the plate and in fact support it and create turbulence, so that the limestone bed is moving around and is expanded by the air passing through it.

If you then heat that limestone to incandescence and then introduce the fuel, the coal, then the coal ignites and the process then becomes self-sustaining in that the coal is providing the heat to maintain incandescence and provide heat, and the hot

gas then moves up through the boiler and through past the heat exchangers and produces steam in the same way that the conventional steam cycle does.

One of the advantages of the technology is that you can introduce heat exchanger surface into the bed and you get very good heat transfer in that surface and that tends to make the boiler somewhat smaller than it would be for conventional steam cycle.

Q. Are there other advantages?

A. As I have mentioned, you do get a long residence time in the bed and as a result you don't need to grind the coal to the fine sizes needed for conventional steam cycle technology, so there is no large investment in grinding equipment.

It's tolerant of low grade fuels because of this same characteristic of long residence times. It operates at a relatively low combustion temperature, at about 900 degrees Celsius, and that's useful in that it allows the limestone that's available in the bed to capture the sulphur dioxide that's produced, and you can achieve 90 per cent removal of sulphur dioxide in the bed without having to put a scrubber on the back end of the system.

It also, as a result of those relatively low temperatures, it limits the NOx emissions to

roughly 100 parts per million, which is about .3 grams per kilowatthour.

The disadvantage of that is that you do have a larger amount of reactivate waste which has to be taken out as ash because of the limestone that has to be removed from the bed as well as the coal ash.

Q. When you say reactive waste, what is included in the phrase "reactive waste"?

A. Well, because what you have done essentially to part of that limestone is calcined it so you have quick lime which is very reactive, particularly if it contacts water and can get very hot and therefore you have to treat the waste with water and slake it prior to disposing of it.

Q. And the expected life in this technology?

A. In the thermal cost review again we have assumed 30 years largely because of our limited experience with the technology, and the fact that because you are moving all this granular material around in the boiler there is a high potential for erosion. So, for the time being we have said we think it's probably good for 30 years but we are not sure beyond that.

Q. You have been talking atmospheric

fluidized bed, are there other fluidized bed combustion methods being developed?

A. Yes, there are two. There is a technology called circulating fluidized bed.

Essentially what happens there is that the gas velocity through the bed is increased to the point where it actually carries the material out of the bed and right through the boiler and it is then collected in a cyclone at the back end of the boiler, and that technology is described in the thermal cost review, Exhibit 35.

Again, because the retention times in the boiler are even longer because its carried all the way through the boiler, you tend to get slightly improved sulphur capture and you can achieve a somewhat smaller boiler again with that approach.

That technology is developing very rapidly. Nova Scotia Power for instance is in the process of designing and installing 165 megawatt unit. at Point Aconi.

The other technology is called pressurized fluidized bed, and there it's essentially the same approach as atmospheric fluidized bed but the entire boiler is encapsulated in a pressure vessel, and because the whole system is pressurized it can be made

much smaller. And because you have now got a flue gas which exits the boiler under pressure, it can be used to drive the gas turbine and therefore you can apply it to combined-cycle technology. That is currently being demonstrated at about a 70 megawatt scale in Ohio and also in Sweden.

Q. All right then, that is a general description of the five technologies. Can we now turn to environmental control technologies which have been mentioned. Would you tell us which technologies you are going to describe?

A. Yes. I will talk a little bit about technologies for collecting particulate and for collecting sulphur dioxides and nitrogen oxides.

Q. Let's start with particulate control. What are the options?

A. There are two basic approaches. Electrostatic precipitators which you have already heard a little bit about and fabric filters which are also known as bag houses.

Q. And electrostatic precipitators, you have got a diagram of one.

A. Yes. The next overhead, D9, if you recall on the coloured overhead which showed the boiler, it also had an external view of an

electrostatic precipitator and about the centre of that D9 shows the internals of an electrostatic precipitator.

It consists of a vertical discharge electrodes which are the spiked wires shown between the two plates, and collecting plates. Those are shown on either side of the discharge electrodes.

[3:19 p.m.]

To give you some idea of scale, those plates are about 10 metres from top to bottom.

Q. It would be better in feet for me.

A. That's about 30 feet, roughly. And the spacing between the plates is about a quarter of a metre or 10 inches between the plates.

On 500 megawatt units such as the ones you saw at Nanticoke there would be perhaps 60 gas passages all in parallel, like the one shown there, so that the width of the precipitator would be about 20 metres.

The wires are charged to a high voltage, and the collecting plates are grounded, and, as a result, a corona discharge is set up between the collecting plates and the discharge electrodes, and this ionizes the flue gas and in fact charges the flyash particles as they pass down the gas passages,

and the charged particles are then attracted to the grounded collecting plates and, in fact, adhere to the collecting plates.

As the deposit then builds up on those plates the plates are periodically rapped by lifting them perhaps a quarter of an inch and dropping them, and that induces the collected material to slide off the plate down into a collecting hopper which is located below them, and from there the ash is taken out and either recycled or landfilled, as I have mentioned.

Q. What level of performance would you expect from your electrostatic precipitators?

A. A modern design would achieve 99.5 per cent or better. 99.7 per cent removal is not uncommon. I should point out that that in fact is - if you look at it from the point of view of the amount of material that's being discharged - that's a 40 per cent improvement over the 99.5 per cent removal.

Q. Can you tell us something about fabric filters?

A. Yes. My next overhead, D10, in fact has two pictures. The upper picture is a cut-away diagram of a fabric filter, which shows in fact two compartments of filter bags. Those are shown on the left front corner, and the gas inlets, you can actually

see two gas inlets there.

That whole thing, again for a 500 megawatt unit, would be about 35 metres long by 20 metres high and 20 metres across. It would have about 30 compartments inside it, of the filter bags, and each compartment would contain about 120 filter bags, and each of those filter bags would be about eight inches in diameter and again about 10 metres long from top to bottom.

The bottom diagram describes the operation, and the picture on the left-hand side shows the normal operation of the fabric filter where the flue gas is entering through actually what is the ash hopper and it passes up through the centre of the bag and passes through the walls of the bag, and in so doing the ash particles are filtered out and left on the inside of the bag, and the clean gas then exits through into a gas duct which takes it away to the stack.

When the deposit on the bag becomes thick enough that a pressure drop starts to be sensed across the bag or the compartment, then the flow of gas is reversed, and in reversing the flow of gas that tends to collapse the walls of the bag, and that in fact releases the cake of ash which is collected on them,

and the ash then drops down the centre of the bag and into the hopper at the bottom where it's collected and removed.

Then, once that has been achieved, the dampers are again reversed and the normal flow of gas takes place and the gas again enters at the bottom and passes up the centre of the bag so that filtering of the dirty flue gas once again takes place.

Q. What kind of performance would you expect from fabric filters?

A. You would tend to get better than 99.7 per cent removal, though you have got to remember that occasionally you do get a bag failure. Bags can burst, and when that happens you tend to get discharges of fairly high particulate loadings until that compartment can be isolated.

Normally, the bag life would be three to five years. The disadvantage of that technology is that it tends to use a fairly high amount of energy due to the pressure drop across the bags. That means you have got to have a bigger fan to drive the gas through the filter system and out of the stack.

Q. Can we turn now to sulphur dioxide control? What are the approaches to that?

A. There are three approaches. You can

remove sulphur from the flue gas as sulphur dioxide after combustion; you can remove sulphur dioxide from the flue gas during the combustion process; or you can remove sulphur in whatever form it's in from the fuel prior to combustion.

Q. Let's start with removal after combustion. How is that done?

A. That technology is normally known as flue gas desulphurization or sometimes known as sulphur dioxide scrubbing. There are a whole range of technologies for removing the sulphur dioxide from the flue gas, and Hydro has selected three which we believe to be most applicable to our needs.

Two of those - one is called limestone slurry scrubbing and the other one is known as a limestone dual alkali process - are suitable for scrubbing flue gas from medium sulphur coals, and it's suitable for application to conventional steam cycle technology or atmospheric fluidized bed technology if it was needed, though it likely isn't.

You can achieve 90 per cent removal with those technologies, and the actual process, as I described in the thermal cost review, Exhibit 35, both of those technologies would produce a waste which is gypsum, which can be used to produce wallboard.

Q. You said there was a third one. What's that?

A. The third one is a technology known as lime spray dryer, and typically that's applied to lower sulphur coals, though if we were going to use a lower sulphur coal it would normally achieve about a 70 per cent removal of sulphur dioxide, and it produces a dry product. And again, there is a process description in the thermal cost review, Exhibit 35.

Q. Then you mentioned the second approach was to remove SO(2) during combustion in the furnace?

A. Yes. Limestone can be ground to a fine size and injected into the furnace, and this technology can be applied to conventional steam cycle or again to -- well, in fact, it does apply to fluidized bed, as I have already described. That relies on the limestone bed in the furnace.

For conventional steam cycle it is not terribly effective and normally you would expect to achieve maybe 40 per cent removal of sulphur dioxide, and the reasons for that are that it is very difficult to achieve good mixing of the limestone when it's injected into the furnace with the flue gas, and it's also difficult to inject it into the furnace at the

right temperature range.

There is a critical temperature at which the reaction takes place, and if you inject it at above that temperature then the limestone fuses and loses its reactivity, and if you get below that temperature then it doesn't react. So it's very critical to have the right temperatures, and they tend to move in the furnace depending on load, and all in all it's a rather difficult operation to achieve.

For fluidized bed, as we have already mentioned, limestone is in the bed and you have long residence times and you have of the ideal temperature, and that's why you can achieve 90 per cent removal with a fluidized bed.

Q. The third approach you mentioned was removal from the fuel prior to combustion?

A. Yes. Sulphur compounds can often be removed from the fuel. An example would be with coal. The sulphur is present in the coal in two forms, one of them being iron pyrite, and that in fact is a separate mineral which is just embedded in the coal, so if you grind the coal to a relatively fine size the pyrite can be separated from the coal, and that's usually done by flotation or density separation. Coal in fact will float in water, whereas the pyrite sinks.

The other sulphur component in the coal, which is organic sulphur, is chemically bonded to the coal, and that can't be removed in that way, and therefore the amount of sulphur removal you achieve depends on the relative percentages of the pyrite to the organic sulphur.

Natural gas also has sulphur compounds in it when it's taken from the well, and those sulphur compounds are normally removed by scrubbing it with a solvent in much the same way as I described for the gasification combined-cycle process, and that's done prior to transmission in the pipeline. Typically, you would get about 98 per cent removal of those sulphur compounds that way, and the sulphur is normally produced as a by-product of that process.

Q. We would also like to deal with the technology for NOx control. Can you describe what's available there?

A. Yes. Nitrogen oxides form as a result of the combination of nitrogen, which is available both in the -- in many fuels and in the air, and oxygen which is available in the combustion air during the combustion process.

Control can be either through the combustion process itself or through technologies which

reconvert the nitrogen oxide back to elemental nitrogen.

Q. Let's talk first about controlling the combustion process.

A. The approach to control of the combustion process depends on the technology that we are talking about, and by that I mean whether it's conventional steam cycle or gas turbine technology.

For conventional steam cycle -- maybe I should start out by saying that ideally a boiler designer is trying to achieve very intense combustion within the boiler. He wants to produce as hot a flame as possible in order to maximize heat transfer, and under those circumstances the nitrogen oxide emissions would be very high and would be in the 500 to 700 parts-per-million range.

The production of nitrogen oxide is dependent on both the flame temperature and on the availability of the nitrogen and the oxygen within the flame. So therefore, the approach to control of nitrogen oxide is to limit the flame temperature and also to limit the availability of the oxygen to mix with the nitrogen that's in the fuel.

Overhead D11 is a diagram of a typical low NOx burner, though the burner design does vary from

manufacturer to manufacturer.

The whole purpose of the burner design is to limit the air supply to the flame, and in the conventional burner design virtually all the air would be introduced through the central pipe along with the finely ground coal that would be ignited as it entered into the furnace.

With the low NOx burner, the key points to note, I think, are you will note that there are some inner vanes and what are labeled as "internally adjusted outer vanes", which in fact sit around the periphery of the internal air and coal supply pipe.

So what happens with the low NOx burner is that in fact the amount of air that is supplied with the coal is reduced and air is supplied through these outer vanes, and the vanes are used to direct the air and control the mixing of the air with the flame.

As a result of that, you tend to produce a long, lazy low temperature flame which typically reduces the nitrogen oxide emissions to around the 300 to 350 parts-per-million. So you can achieve about a 50 per cent reduction from what would be uncontrolled levels of nitrogen oxide.

[3:35 p.m.]

That's the technology that's applied to

conventional steam cycle systems.

For combustion turbine units it's a lot more difficult to achieve delayed mixing because you have a relatively small combustion chamber, so the approach there is in fact to limit the flame temperature and that's done by mixing the combustion fuel in the air with either water or steam. That can typically produce nitrogen oxide emissions which are about a quarter of those that are produced with conventional steam cycle. Manufacturers are in fact working to achieve lower levels than that. They are trying to achieve nitrogen oxide emissions of about 9 parts-per-million.

Q. All right. Then can we turn to the post combustion controls of NOx?

A. Yes. Overhead D12 presents a number of nitrogen oxide reduction alternatives.

Nitrogen oxide can be reduced by ammonia-based chemicals under the right circumstances, and by the right circumstances I mean if the ammonia is in the form of urea then it will react with nitrogen oxides in the temperature range of 870 to 1,000 degrees Celsius and form elemental nitrogen and water.

Alternatively, if you introduce the ammonia as ammonia, that will react with nitrogen

oxides in the presence of a catalyst that is about a 350 degree Celsius temperature.

Urea injection can be applied to conventional steam cycle or fluidized bed technologies, and as you can see on the diagram, it would be injected into the top of the furnace, and that's about the area where you see the temperatures in the range of 1,000 to 870 degrees Celsius.

Like the limestone injection technology it's difficult it achieve good mixing of the urea with the flue gas, and again that temperature window is small and it tends to move with the boiler load and therefore it's difficult to get it in at the right place at the right time, and as a result of that again we think practical removal efficiencies are likely to be in the 40 per cent range. However, it's a significantly lower cost than the selective catalytic reduction technology which is the technology that uses ammonia and a catalyst which I will talk about now. As a result of that we are planning to demonstrate the urea injection at Nanticoke just to find out what the real costs are, and in fact what removal efficiency we can achieve. It may turn out to be more cost effective than selective catalytic reduction.

Selective catalytic reduction is more

expensive, you require a large volume of what is an expensive catalyst, it contains vanadium and titanium, and molybdenum. You need a structure to house the catalyst and to guide the flue gas through the catalyst. You also require large ammonia storage and management system.

The technology has been used extensively in Japan and in Germany on low sulphur coals, but it hasn't been used much in North America and it hasn't been used very much on high sulphur coals, and there are concerns for potential for catalyst poisoning as a result of trace elements which may be present in the coals and for fouling as a result of the formation of ammonium sulfate downstream of the catalyst which is sticky and it can plug the air preheater, for example, which is downstream of the catalyst.

As a result of that we are planning to build a one megawatt pilot facility to evaluate those problems and ensure to our satisfaction that we can get 80 per cent removal, that it is achievable and that we can get it with reasonable catalyst lives and without major problems with plugging and fouling downstream of the system.

That technology can be applied to conventional steam cycle and that's where we would see

these types of problems that I have just discussed occurring. It could also also be applied to combined cycle, to gasification combined cycle, or to fluidized bed.

Q. All right. Then can we turn now to any other emissions that require control?

A. Yes. I think we have covered off the main gaseous emissions that are of major concern.

There are liquid effluents though that have to be dealt with and there are a whole range of technologies depending on the contaminants that can be applied to clean up liquid effluents.

We are currently in the process of discussing improvements using those technologies at our existing stations with the Ministry of the Environment, and Dr. Effer has already referred, I think, to the MISA program, and that may lead us to in fact more recycling and reuse of waste waters.

The other issue is cooling water, cooling water intakes and discharges have impacts on lake biology, and I will be dealing with those a little later in my presentation.

Q. As you have been going through it's clear that depending on which of the generating technologies you use, you have to combine it with the

emission control technologies. Could you go through the combinations, please, for each of the processes, the five processes we have been talking about, first conventional steam cycle.

A. Yes. Overhead D13 describes the combinations that are available for conventional steam cycle.

Over on the right of the diagram it shows low NOx burners, which I have described, and those certainly on a new installation would almost certainly be used because they are cost-effective. And then beyond there we can see that selective catalytic reduction can also be applied to conventional steam cycle, so that also is an option for that technology.

For SO(2) control we could either burn very low sulphur coal or alternatively use one of the three scrubbing technologies which I discussed. The SO(2) scrubber is shown to the immediate right of the stack on that diagram.

For particulate removal the options are either electrostatic precipitator which would be preferred if we are using higher sulphur coals where the ash resistivity is in the ideal range, and as I mentioned that could achieve a 99.5 per cent removal or better.

For very low sulphur coals where you have non-ideal ash characteristics for electrostatic precipitator performance, then it may be that a fabric filter would be the preferred option.

All those choices would be made during the definition phase of the design.

MR. HOWARD: We are planning to come to water now, sir, if this is a good time for a break.

MR. DAWSON: Overhead D40 --

THE CHAIRMAN: Hold it.

MR. HOWARD: I just got us a break.

THE CHAIRMAN: 15 minutes.

THE REGISTRAR: A 15-minute break.

---Recess at 3:45 p.m.

---On resuming at 4:00 p.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Please be seated.

MR. HOWARD: Q. Mr. Dawson, when we broke you were about to deal with water emissions and controlling that problem?

MR. DAWSON: A. Yes. Assuming that the generating station would be located on the Great Lakes Ontario Hydro's preference would be for once-through cooling. The next overhead shows what is our most recent design of an intake and discharge system for a

once-through cooling system.

The upper part of the overhead shows an arrangement of the intake system. It's a system that we call a porous bottom veneer intake system, and each of the modules shown in that diagram is essentially like a four-legged stool, and then the upper surface of each of those modules is rather like a ventilation grill. Each module, though, is about 12 feet high. So that gives you some idea of the scale.

That entire intake system is roughly the size of a football field, and this is the design that's actually used at Darlington, and that's located on the bottom of Lake Ontario offshore from the Darlington station.

The advantages of that type of intake design are that it produces a very low flow velocity through the actual intake structure, and that therefore allows the fish to move out of the flow and it's low enough that they aren't entrapped or impinged on the intake structure.

It also provides a visual aid for any fish in that they see the intake structure as they approach it and are able to swim away from it. We think it will prove to be very successful in terms of minimizing the fish impingement and entrapment at

Darlington.

Q. Just before you leave that, on my hard copy of D14 I can't see the "3" and I take it that that is in the upper-most white circle which you have identified as a porous module. Is that "3"?

A. That's right. That's around the outer periphery of the design, and in fact, over the vertical intake pipe the modules are solid to prevent water flow directly into the pipe. This is to make sure you get a good distribution of flow through the entire surface or through the outer periphery of those modules.

The lower portion of the diagram shows the discharge tunnel, and again, this is the design that is being used at Darlington. What it shows is a tunnel which is actually under the lake bottom, and it's roughly 30 to 40 feet in diameter, and that's where the warm cooling water is pumped.

Then there are a series of vertical shafts which penetrate the lake bed and culminate in a nozzle which is above the lake bed, and the warm discharge water is discharged through those nozzles and entrains cold lake water as it discharges and mixes, and the design is such that it has been designed to ensure that in fact within a square kilometre of that

discharge section of the tunnel the lake temperature will be no more than one degree celsius above the ambient lake temperature.

Q. So those are the control technologies for conventional steam cycle. Can we turn now to the combustion turbine units?

A. Yes. For combustion turbine units, of course, they burn natural gas or distillate oil and therefore there are no particulate emissions or sulphur dioxide emissions of significance, and therefore the only pollutant of concern is nitrogen oxides.

As I mentioned, we use water injection to achieve -- current technology is capable of achieving about 25 parts-per-million of nitrogen oxide emissions from a gas turbine.

The exhaust gas is too hot to use selective catalytic reduction technology, so that's currently about the best that can be achieved, and with gas turbine technology of course there is no cooling water requirement.

Q. Then, combined cycle?

A. Again, combined cycle uses premium fuels so that nitrogen oxides are the only emissions of significant concern.

In that case, rather than using water

injection the steam injection would be used. It achieves the same objective of controlling the combustion flame temperature, but it's more efficient to use steam than water.

In this case, we could add selective catalytic reduction because the exhaust gas from the gas turbine is cooled in the heat recovery boiler and therefore the temperatures are down low enough that selective catalytic reduction could be applied if necessary, and that would in fact be installed partway down the heat recovery steam generator, if necessary.

The needs for once-through cooling are there because we now have a steam turbine generator, but in fact it would only be about a third of the size of a conventional steam cycle plant of equivalent output.

Q. Integrated coal gasification combined cycle, IGCC?

A. Again, the emission control technology would be similar to combined cycle, and as I mentioned earlier, the fuel gas itself would be cleaned up prior to combustion to remove sulphur dioxide forming elements which would be -- sulphur in it would be there probably as hydrogen sulfide in the fuel gas.

Again, you would need a once-through

cooling system, and it would be slightly larger than for a conventional combined-cycle plant because you do have some additional heat recovery and steam generation in the gasifier itself.

Q. Finally, atmospheric fluidized bed technology?

A. As I mentioned earlier, the sulphur dioxide capture takes place in the bed itself, within the boiler. As a result of that, you do need a large limestone handling facility, somewhat larger than would be the case with a flue gas scrubber, and you also need large ash handling facilities because of the large amount of waste that you produce.

Particulate control for atmospheric fluidized bed technology could be either electrostatic precipitator or fabric filter, and that would depend on the ash characteristics.

Nitrogen oxide emissions are low, as I mentioned, because of the low combustion temperatures, and again, selective catalytic reduction could be added if it was required.

Q. Now, then, perhaps you could describe for us why the 10 options that are in the thermal cost review and in the DSP were selected?

A. Yes. Overhead D15 provides a table

of the 10 options that were selected and reviewed in the thermal cost review.

That comes from the thermal cost review itself, Exhibit 35, and it's actually figure ES-3 out of Volume 1, page 5. The 10 options were selected to try to ensure that each technology was examined for the range of conditions for which it might be most advantageous.

The evaluations were based on what I would call good quality study level information, which is consistent across the fossil options. And that was used to prepare all the estimates.

There is considerable detail provided on the basis of those estimates in the thermal cost review.

The 10 options that were selected are, as I say, shown on that table, and option 1 was the 4 by 800 megawatt conventional steam cycle, and that's shown at the first line of the table under the headings. That option was assumed to burn 2-1/2 per cent sulphur coal and to be fitted with flue gas desulphurization, and, in fact, in the update with selective catalytic reduction.

It allows us to assess the cost and performance of a large conventional steam cycle plant

that would be base loaded and using what is a relatively low cost fuel.

Option 2 is a four by 500-megawatt station burning the same fuel, and again with the same environmental control technology, and that allows us to assess the cost and performance of a mid-sized plant, and that is in fact under intermediate load conditions.

Option 3 is again based on the same conventional steam cycle technology. It is the same size as option 2, but there we have looked at a different fuel. We have looked at low sulphur Western Canadian coal, and there, rather than having flue gas desulphurization, we have just added selective catalytic reduction. So there is no flue gas desulphurization because we are using low sulphur coal. It allows us to assess the alternative of low sulphur coal to flue gas desulphurization, and it's a tradeoff with a somewhat higher fuel cost for the Western Canadian coal.

Q. Then, coming to the combustion turbine options?

A. Yes. Combustion turbines are options 4 and 5.

Here we have looked at two what are nominally 150 megawatt CTUs. In fact, under low

temperature winter conditions they would achieve 170 megawatts in output. They do so though with low thermal efficiency, and here we have a high fuel price which makes them options for peaking.

Option 4 uses oil and option 5 uses gas, and it allows a comparison of the two fuels for this service, bearing in mind that option 5 has oil backup so that we are looking at an interruptible gas supply rather than a firm gas contract.

Q. Then the next ones are combined cycle?

A. Yes. Option 6 and option 7 are combined cycle.

Option 6 is in fact a two by 700 megawatt combined cycle configuration. There would be three of the 150 megawatt gas turbines combined with three 80 megawatt steam turbines in the case that we actually looked at.

Q. Why have we got 660 in the figure, then? I should have asked you that before now.

A. The 660 is a carryover from the 1989 study and is really based on more moderate temperature conditions. The 700 megawatts is achievable under winter conditions.

That's one of the things about gas

turbines. The output varies with the temperature, and you get higher outputs under cold temperatures.

Because it's combined cycle we have higher efficiency, but again, a high fuel cost in that we are looking at natural gas.

And option 6 assesses that option under intermediate load conditions, and option 7 is essentially the same option but assessed under peaking conditions. Again, for option 7 because of the peaking conditions we have assumed that there would be oil support and an interruptible gas supply.

Then option 8 and option 9 are the gasification combined-cycle options.

Option 8 is a four by 700 megawatt integrated gasification combined cycle, so this allows us to assess the benefits of coal-fueled combined-cycle plant. Option 8 assumes a phased approach, first CTUs then moving to combined cycle, and then to gasification. It has an intermediate annual capacity factor of about 40, 45 per cent, and it has the same unit arrangement as option 6 but with four gasifiers added per unit.

Option 9 is the same option, but this time we have assumed that we would install the gasifiers on the entire system right from the outset,

and it's a base loaded alternative to the conventional steam cycle, option 1. And as a result of that, it has a more efficient gasifier than option 8.

Option 10 is the four by 200 megawatt atmospheric fluidized bed combustion system.

We selected 200 megawatts since that's about the maximum size that is commercially available. Again, it's base loaded and uses the same coal as option 1, so it's assessing the option under favourable conditions in terms of coal cost, and it allows a comparison with option 1 and option 9.

Q. You have been talking about the thermal cost review, and, as you know, it has been updated. A summary of the update is Exhibit 465. Would you explain why that was done?

A. Yes, the thermal cost review was based on 1989 information. In the meantime, we have done some additional work inside Ontario Hydro and there have been some additional consultant studies done in some areas since then.

Therefore, we took the opportunity to do a further review and compare the more recent information with the original '89 information and make changes where we felt that they were warranted.

Q. Could you, for the Board, summarize

the costs of the options which we have been looking at and highlight any significant changes as a result of the update?

A. Yes. Just before I do that I would like to refer to overhead D16A, which is the simple cost model which I think you have probably seen before. It's presented in the thermal cost review. It's figure 11-4-8 in the thermal cost review.

I am going to discuss the initial capital costs for construction, which is under the "Capital" column on the left-hand side of the diagram, and I am also going to talk about the later capital modifications, which is again in that same column but in the lower box.

I am not going to talk about decommissioning costs. We didn't review the decommissioning costs. They're small in the overall picture.

And Mr. Burpee will talk about the commissioning and training costs that are under "Capital" as well as talk about the direct and indirect OM&A costs.

Mr. Smith will deal with fuel costs in due course, also.

Q. All right. Then, let's start with

conventional steam cycle. You'll have to help us through this table.

A. Yes. It is a rather busy table. That's table, overhead D16B

What we have done is extracted that specific information that I am going to talk about out of that thermal cost update table. So this doesn't show all the costs. It just shows the initial capital construction, the later capital modifications, and the performance information, and it also shows the total LUEC cost just for reference, although I am not going to discuss that specifically.

For conventional steam cycle, which are the first three options, 1, 2 and 3, there have been some small changes to the output and the efficiency, and they were made as a result of some perhaps more detailed heat and mass balances that we have carried out in the meantime.

Q. Where do we find that on the summary?

A. Those are under the column, the third column across. It says "Net Maximum Continuous Rating", and then the fourth column across is headed "Design Efficiency".

The right-hand side of those two columns shows the percentage change, and you can see that for

option 1, for instance, there has been about a .6 per cent change in the primary output and a .6 per cent in the primary output plus FGD and a 1 per cent change upwards when we add selective catalytic reduction.

Those are, I should point out, not percentage point changes; they're just overall percentage changes. So it's quite small. When I referred to percentage point I was thinking of the efficiency changes.

So, in fact, the largest change that we have in design efficiency is for option 3, and with SCR it shows a change of about 6.1, and so that's about a 6 per cent change in design efficiency, which would in fact bring the design efficiency up from the original value which was about 35.8 up to the new value of 38.1.

[4:35 p.m.]

Q. So the values under that maximum continuous rating are the values in the update, and then the percentage delta refers to the similar numbers that were in the thermal cost review?

A. Right. That shows the change from the number that was in the original thermal cost review, that's right.

Q. And the same thing under design efficiency?

A. That's right, yes. And that's what I was just referring to was the 6 per cent change in the design efficiency of option 3, was selective catalytic reduction.

Q. Then staying with those three options, coming over to capital initial and later, what happens there?

A. The overall initial capital estimates have reduced overall by about 7-1/2 per cent, and as you can see that's made up of somewhat different values for the primary and the FGD and the SCR. Both the primary and the FGD costs have come down and the SCR costs on the other hand has gone up, so that tends to counter-balance the reductions in the other two items, and overall that balances out to about a 7-1/2 per cent reduction.

Q. That's initial capital?

A. That's the initial capital.

And then the later capital, the only change that has been made there is to the flue gas desulphurization costs, and as you can see, we have changed those quite drastically. There is a 200 per cent change. That was done because I don't think in the original estimate that the complexity of the flue gas desulphurization was recognized, and that change

now brings the FGD later capital modifications costs in line with the primary plant costs in terms of as a ratio of the initial capital investment.

Q. Then what about CTU technology, what is the effect?

A. Essentially there were no changes made to CTU technology. We did have some new information from suppliers and when we reviewed that we felt there was no need to make any significant changes.

The only change we did make was to add a small amount of money for environmental approvals, and that has resulted in about a 2 per cent change in the initial capital cost, as can be seen, lines 4 and 5 show a 2 per cent increase in the initial capital.

Q. Now, I notice in the net maximum contribution and design efficiencies there is an asterisk, and we go down to the bottom of the page and we see at minus 7 degrees C, why is that there?

A. That's just to point out the fact that I mentioned a few minutes ago that in fact the output of gas turbines varies with the ambient temperature, so that at a higher temperature the output would be lower.

Minus 7 degrees C is a standard temperature that's used to talk about gas turbine

output.

Q. Then coming to the combined cycle.

A. There have been some small increases in the output and efficiency of combined-cycle plants based on again mass and heat balances that have been carried out.

The initial capital cost has reduced by about 10 per cent for the primary plant and by about 50 per cent, which again is a significant change for the selective catalytic reduction plant for those combined-cycle options.

The selective catalytic reduction option applies to 6. It hasn't been shown on option 7 which a peaking alternative.

Q. All right.

A. There were no changes to the capital mods for combined-cycle.

Q. Then the next two are IGCC?

A. Yes. The output for the IGCC option has an increased significantly for the gasification phase in option 8, and that's primarily because of some consultant work which looked at a different optimization for the plant, and in fact installed a gasifier than was the case with the earlier work that we had done, and that results in more heat recovery and

a bigger steam turbine, more steam turbine output.

The capital cost for the gasification phase has also an increased significantly as a result of the fact that it is a bigger gasifier. And the selective catalytic reduction cost has reduced as it did for the combined-cycle option.

Q. I forgot to ask you up above, in option 6 there is a double asterisk there, and at the bottom of the table, that "includes other". What does that mean?

A. I think...

Q. Good question.

A. I think it relates to...

If we go back to the cost model, I think it -- I'm not sure.

I'm not sure. I will have to go back, Mr. Howard, and find out and tell you what that asterisk means later.

Q. I will take that undertaking. I should have asked you the question last week.

Atmospheric fluidized bed?

A. We haven't actually reviewed atmospheric fluidized bed. We had no additional information on which to use as basis for any change, and therefore those costs are the same as were shown in

the thermal cost review.

Q. All right. We have been through some of the details. Can you summarize for us the effect upon capital costs of the update?

A. Overall there are a few significant changes as we mentioned. The capital mods of FGD increase significantly. But overall, they are small in terms of the overall cost and generally the review tends to support the costs that were in the original thermal cost review.

Q. Okay. Now, Mr. Burpee, as advertised you are going to deal with the OM&A costs with respect to the costing update and the costs.

First of all, could you start by reminding us what is in OM&A?

MR. BURPEE: A. Station operating maintenance and administrations costs are those associated with primarily with the day-to-day operation of the station, excluding the cost fuel.

Q. Okay. And what is included? I know this is all set out in the DSP, but...

A. Shown on overhead B3 --

Q. Hang on. That's Exhibit 472. You have got B3, which is schematic from the thermal cost review?

A. Right. It's figure 0-13-2.

Q. Can you just point out to us the important elements of this from an OM&A point of view?

A. Yes. The OM&A is broken into direct and indirect costs, and for FGD plants there is cost reagents and waste disposal.

Direct costs --

Q. Where are we looking at?

A. The OM&A is the centre column under primary plant, which is on the left.

Q. Right.

A. Middle branch is OM&A direct and indirect. In the centre is the FGD plant. Again OM&A is in the centre of that grouping of three, and there is direct, indirect, reagents and disposal. That's the disposal of the waste of the scrubbers and --

Q. That's where there is flue gas desulphurization?

A. Yes. And the SCR plant, for OM&A it has direct and indirect costs as well.

The direct costs are labour, materials, purchase services, and training directly associated with the station.

Ash disposal is also an OM&A cost but for the purposes of the thermal cost review they have been

included in the fuel cost component.

Indirect costs are made up of specific overheads and corporate overheads. A specific overhead is the cost of central support groups, research, design, and corporate overheads are corporate planning and administrative activities that are not directly attributed to work in the station but must be charged to the cost of power.

Q. Would you just indicate briefly for us how OM&A costs are estimated?

A. The process is described on pages 148 and 149 of the thermal cost review.

Basically, the costs of labour, material, purchase services, reagents and disposal are based on our experience and information from other sources which include other utilities.

Q. When we look at the ten options, each one of them has a specified capacity factor for comparison purposes. Do OM&A costs change if the capacity factor changes?

A. Some costs are not sensitive to capacity factor, we refer to these as capacity or fixed costs, and they reflect staffing and work required to have a station ready to produce energy. This would cover the cost of operators, coal yard staff, if it's

coal-fired, and some maintenance and administration staff.

The bulk of the maintenance is an energy or variable cost. As the station produces more energy, more maintenance or work is required.

Some costs are incurred in the year the energy is produced, an example would be ash disposal or fuel and maintenance for coal yard mobile equipment. Some costs are incurred in subsequent years which is work requiring maintenance due to wear caused by the energy production.

Q. Obviously all the options don't vary at the same rate, can you explain that, please?

A. Yes. Coal options have the greatest sensitivity due to the erosive nature of coal and ash. Gas options don't have equipment subjected to the same amount of wear.

All options are similar in wear with respect to rotating equipment such as pumps and turbines and metallurgical damage such as creep and fatigue to boilers, piping, and turbines.

Q. All right. First of all then, options 1 to 3, the conventional steam cycle, have there been any changes in the OM&A in the thermal cost review as a result of the update?

A. Overhead B4 is the breakdown of the changes similar to what Mr. Dawson showed for the capital costs. Here we have just showed the capital commissioning and training and the OM&A changes.

Q. You had to put in training because you were going to deal with any training changes which --

A. I will start off with the OM&A and then get back to the initial capital training.

Q. All right.

A. For options 1 to 3, which are the conventional steam cycle. We reviewed Lambton as to what they are currently doing and what they have in their business plans, and that's resulted in an increase in staffing for the primary plant and the FGD plant, and scrubbers.

For option 3 staff is increased slightly relative to option 2 to reflect increased coal and ash to be handled as a result of the lowered heating value of the western Canadian coal.

A review of reagent price for Lambton has also resulted in lower reagent costs for all three options.

The net result, however, are increases in OM&A costs for all three options, and you can see that

under the column headed OM&A.

Primary plant for all three have gone up. For option 1 you see that the FGD plant has stayed about the same, and that's increased staff costs have been offset by lower reagent costs at the high capacity factor. For option 2 the FGD costs have gone up as a result of the increased staffing.

Q. All right. Now, what about options 4 and 5, the CTU options?

A. For options 4 and 5 we have not changed any staffing requirements but the material and purchase service rates have doubled based on more recent information. That results in increases to both options. While they look large here in percentage, they are relatively small figures to begin with.

Q. Options 6 and 7, the combined cycle?

A. We have lowered the required staff levels considerably based on information we have gathered from other sources including the utility experience.

The material and purchase service costs have been increased based on similar information sources, but there is a fair reduction in OM&A to both options.

Q. Options 8 and 9, the IGCC option?

A. Staffing for the combined-cycle portion has been reduced as per option 6 and 7, but increased for the gasification portion.

Material and purchase service costs have also increased.

The net result is an increase in OM&A. Although option 8, when you see it, the numbers listed here are a little confusing, they are cumulative as you go down.

So, for the first phase you will see that it is -- the CTU phase is only marginally more expensive. To explain that relative to options 4 and 5, 4 and 5 are based that the CTUs would be an operating station, so the staff requirements, the incremental staff requirements are very low.

Option 8 would be at a station that doesn't have support staff or a base amount of staff already on-site. So there was a higher staffing requirement which is actually reduced during the review.

The combined-cycle phase, once you get to that again reflects the reduced staffing requirements, and the gasification phase brings it backup to -- well, it shows zero change here but that's also dependent on the timing that the three phases will go in and how

much they would operate.

The true impact of the change in the IGCC option can be seen better in option 9 numbers.

Q. All right. And finally, the atmospheric fluidized bed, option 10?

A. As Mr. Dawson has already stated, there is no new information that would lead to us change our estimates at this time.

Q. Finally, the changes in commissioning and capital and training and indirects which Mr. Dawson indicated you were going to deal with?

A. Capital training is the initial cost of training the operating maintenance and support staff. Commissioning costs are those incurred in preparing the units for service, and that's done by in general the operating staff.

The changes made to staff levels which I have already described impact on the capital training commissioning and the indirect costs since they are all proportional to labour costs.

Additionally an increase in commissioning energy credits has reduced commissioning costs for primary plants except for the FGD and SCR plants don't get a credit since they don't produce any energy, they only consume it.

Q. Having gone through that, Mr. Smith, I would like to discuss with you the fuel component for a few minutes this afternoon to get you started.

Could we have, Mr. Chairman, an exhibit number for the overheads used by Mr. Smith?

THE REGISTRAR: That will be No. 474, Mr. Chairman.

THE CHAIRMAN: Thank you.

---EXHIBIT NO. 474: Mr. Smith's Overheads.

MR. HOWARD: Q. First of all, Mr. Dawson and Mr. Burpee have just described the capital and OM&A costs of the ten options which are in the DSP and in the thermal cost review. Could you just briefly describe what impact does fuel have on the costs of fossil options?

MR. SMITH: A. Yes. Fuel is one of the major lifetime cost components of any of the fossil options, and in many cases for high capacity factor options it is the major cost element, so in fact it is a major determinant when selecting a fossil option.

As you correctly point out, Mr. Dawson has described and Dr. Effer as well, that a fuel's characteristics affect the design of the plants and the fuel receiving facilities of the plant and ultimately the environmental equipment that must be installed at

the plant.

Q. In looking at fuels in the thermal cost review and in updating them, how do you look at the fuel costs then as a component? How do go about the process of estimating fuel costs?

A. I think I have some information coming up a little later, but essentially we begin to look at the current conditions for those fuels and the various prices that exist, and essentially try to factor in expected changes over a number of years that would affect the price of those fuels, and we have tried to do that for both the thermal cost review and the update.

Q. Okay. Can you just describe for us briefly, there are obviously a number of issues about fuel supply, can you just describe a number of the issues which you address in arranging for this supply?

[4:45 p.m.]

A. I guess the key elements that we think affect the options that have to be considered in our fuel supply are in fact price, and the change in price over time of a fuel, and as we are considering alternatives the relative price of various fuels. So we would want to know how, say, coal and gas would compare over time.

Another issue is the availability of the fuel. If we are going to invest large capital dollars for plants that have 30- or 40-year lives, we want to ensure that we can fuel them with the reference fuel for that life and for the foreseeable future.

We also need to consider the deliverability of the fuel because in the fossil business transportation is a key factor in getting the fuel from its source to the plant.

And then, finally, the various fuel characteristics have to be considered in our procurement strategy.

Q. All right. Before we deal with that in any detail would you begin by describing what fossil fuels you are now buying at Hydro and what factors have to be considered in the fuels you are now buying - fossil fuels, that is?

A. Yes. The primary fuel we use today is coal, and this overhead is put up to show basically how that requirement can vary over time.

This, in fact, is a graph of thermal generation or fossil generation requirements. I am using it as a proxy for coal because, as I said, primarily it is coal.

This graph has got two phases to it or

two parts to it. The first, starting on the left-hand side, measures actual thermal generation, fossil generation up to the year 1991, and the second part of the graph contains a forecast of that generation, which is from one of our forecasting systems. We call it a consistent energy set, basically forecasts what resources will be required and at what level over time.

As you can see from that graph, our fossil requirements, and therefore coal requirements, vary significantly from year to year, and we have had lows of, say, 25 terawatthours and highs of 35 terawatthours over the last several years.

Our fuel supply program for coal must be capable of responding to that variability, and we have to source our coal in places where we can count on them having the ability to in fact respond to the uncertainty we face. So we need to deal with large supply regions and a number of suppliers so that they can respond to our increased needs if they materialize and also to our decreased needs.

The objectives of our coal supply program basically are to deal with that, provide all the coal that is required without creating excess inventories, to get as low a cost as we possibly can, and allow our coal supply program at least not to be a constraint on

our generation system due to emissions.

Q. Can we turn to your overheads to indicate where coal is presently being purchased and where it is being used?

A. Yes. I have a nice coloured graph up there to break up the black and white we have been using.

Q. The hard copy is all black.

A. Yes, it's all black, so...

This graph, basically it's an illustration of our flow of our eastern United States coal to Ontario Hydro, and it isn't in great detail, but in essence it shows that we purchase coal from Kentucky, West Virginia and Pennsylvania.

The yellow indicates delivery by rail to Lake Erie where it is offloaded from the train at ports. We have indicated three there: Toledo, Ashtabula and Conneaut. At those ports the coal is stored during the winter, and during the nine months of the shipping season that the lakes are not frozen we transport the coal by water directly to our major generating stations at Lambton, Nanticoke and Lakefield.

The next overhead deals with another source of coal, major source of our coal, which is from

Western Canada. Essentially, we have the same type of picture.

We buy bituminous coal from British Columbia and Alberta and transport it by rail to Thunder Bay where it is again offloaded at a terminal where it can be stored or loaded onto vessels for shipment through the Great Lakes to the Nanticoke Generating Station, which is where we use Canadian bituminous coal.

The chart also shows an area in Saskatchewan at the very border of the United States. That's where we source our lignite. It's transported by rail directly to the Atikokan Generating Station and by rail to the Thunder Bay terminal where it is then transported by conveyor to the generating station at Thunder Bay. So there is no water transport involved in the lignite supply.

While I have that up, I would just like to stress that the other very important part of our coal supply arrangements is in fact transportation.

Most people don't appreciate the extent of this, but for our business in a typical year we would have 10 vessels unloading at one of our generating stations every week of the year except for the three months when the lakes are closed. We would

have four trains unloading at a terminal every day somewhere in the system. And over the course of a year we have to arrange for over -- about 375 vessel trips in order to transport the coal we need and over 1,500 train trips, and having that transportation system in place is critical to assured fuel supply for Ontario Hydro.

Q. What about current natural gas and oil use?

A. For natural gas we currently only use it as a fuel at Atikokan, and it's strictly an ignition fuel, and we purchase it directly from the local gas distribution company in Northern Ontario.

I have another overhead which talks about residual fuel oil. That is used at our Lennox plant, and the overhead shows that we can deliver that oil from Sarnia by rail or from Montreal by rail after importing it, and even though the graph stops just outside Newfoundland it is not Hibernia oil. However, we do import the oil by vessel through Montreal, and today virtually all of our oil that we purchase is imported because we are buying low sulphur, residual fuel oil, which is not produced by Ontario refineries.

We purchase that oil on an arrangement with Esso where they provide the terminaling facilities

at Montreal for acceptance of the oil and storage, they provide us with a train or set of cars which will transport the oil to the Lennox Generating Station, and they act as our agent in the international oil market.

We currently buy about 2 million barrels of residual fuel oil per year.

Lastly, we use diesel fuel or No. 2 light fuel oil as an ignition fuel at all our other generating stations, except Atikokan, and for CTUs as required. All of that oil is delivered by truck at the moment. We purchase about 70 million litres per year, which sounds like a lot but it represents about .7 per cent of the Ontario refinery capability.

Q. Then, what fuels are considered in the Demand/Supply Plan and in the update, if you can just summarize them for us?

A. Okay. This overhead is in fact figure 14.5 from the Demand/Supply Plan. It lists the options, and we have seen various versions of this already today. It talks about the various fuels we would use at the options, but I would like to just discuss it quickly.

The first two options look at using U.S. coal and nominally 2-1/2 per cent sulphur coal. We would also use that for any of our existing units which

will be run with scrubbers.

Option 3 shows Western Canadian coal. We currently use that at our Nanticoke Generating Station blended with U.S. coal. That is a low sulphur coal.

All our other existing coal units that would not be scrubbed, our plan would be to run them on less than 1 per cent sulphur coal. We currently buy a significant amount of about .8 sulphur coal which is being used at Nanticoke and Lambton, so we would continue to use that fuel even though it doesn't show on this table.

Option 4 is a CTU planned to be run on light fuel oil for peaking purposes.

Options 5, 6 and 7 really look at using natural gas with a backup of light fuel oil, mainly because we don't believe we can get gas on an economical basis for low load factor usage, and we cannot count on it as an interruptible supply.

Finally, even though it doesn't show on -- well, I guess -- I'm sorry, options 9 and 10 also assume 2-1/2 per cent sulphur coal, U.S. coal, as the major source of fuel for those options.

Finally, and not on the chart, but for one of our existing plants we do in fact plan on continuing to use residual fuel oil at Lennox, but, as

discussed by Mr. Meehan, we are also examining the capability of dual fueling that unit on natural gas.

[4:55 p.m.]

MR. HOWARD: Would that be a convenient place? We are coming to a new topic.

THE CHAIRMAN: Yes. We will adjourn until tomorrow morning at ten o'clock.

Mr. Howard, how far are you into your direct?

Be seated for just for a moment, please.

MR. HOWARD: I have undertaken to make a guess for my friends, may I pass it to you after we are finished? We will certainly be the morning, and I will give you a more accurate estimate in five minutes.

THE CHAIRMAN: Mr. Watson, you are starting first in cross-examination?

MR. WATSON: Yes, Mr. Chairman.

THE CHAIRMAN: Followed by Mr. Rodger?

MR. RODGER: That's correct, Mr. Chairman.

MR. HOWARD: I already have the first list of interrogatories, so they are going to have a pleasurable night tonight.

THE REGISTRAR: Please come to order. This hearing will adjourn until ten o'clock tomorrow

morning.

---Whereupon the hearing was adjourned at 4:56 p.m. to be resumed on Tuesday, February 18, 1992, at 10:00 a.m.

# E R R A T A
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# C H A N G E S

To: Volume 107

Date: Monday, January 27, 1992.

| Page No. | Line No. | Discrepancy |
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| 18775 | | Description for Exhibit 466 s/r Alternative Energy Review Errata |